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July 31, 2026

VIA HAND DELIVERY – PUBLIC REDACTED

Louisiana Public Service Commission
Attn: Records Division, Krys Abel
602 N. 5th Street, 12th Floor
Baton Rouge, Louisiana 70802

Re: Docket No. U-37853, Entergy Louisiana, LLC, ex parte., *In re: Request for Approval to Construct Waterford 6 Power Station and Westlake Power Station, and For Cost Recovery*

Dear Ms. Abel:

Please find enclosed an original and two hard copies of the public-redacted version of Environmental Defense Fund's Direct Testimony in the above-referenced proceeding.

Thank you for your assistance in this matter. If you have any questions, please do not hesitate to contact me.

Sincerely,

Megan K. Terrell

Enclosure(s)

cc: All parties of record in Docket U-37853

**BEFORE THE
LOUISIANA PUBLIC SERVICE COMMISSION**

ENTERGY LOUISIANA, LLC, ex parte.

DOCKET NO. U-37853

**IN RE: REQUEST FOR APPROVAL TO
CONSTRUCT WATERFORD 6 POWER
STATION AND WESTLAKE POWER
STATION, AND FOR COST RECOVERY.**

**DIRECT TESTIMONY OF
MARIA ROUMPANI, PhD**

**ON BEHALF OF
ENVIRONMENTAL DEFENSE FUND**

PUBLIC VERSION

JULY 31, 2026

CURRENT ENERGY GROUP, LLC

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¹ Pursuant to Rule 37 of the LPSC Rules of Practice and Procedure, large spreadsheets or voluminous documents were not included so as not to unduly encumber the files and records of the Commission.

I. Introduction

Q. Please state your name, business address, and position.

A. My name is Maria Roumpani. I am a Founding Partner of Current Energy Group, LLC.
My business address is 2900 E Broadway Blvd, Ste 100 #780, Tucson, AZ, 85716.

Q. On whose behalf are you testifying in this proceeding?

A. I am submitting testimony on behalf of the Environmental Defense Fund (“EDF”).

Q. Please summarize your work experience and educational background.

A. I specialize in the economic and technical analysis of grid planning and operations issues. I have conducted analysis and submitted expert testimony or comments on integrated resource planning, plant economics, unit commitment practices, power cost issues, and demand-side management plans before state utility regulators in Arizona, Colorado, Georgia, Kentucky, Michigan, Minnesota, Nevada, North Carolina, Oregon, South Carolina, Utah, Virginia, and Washington.

Prior to co-founding Current Energy Group in 2024, I was the Technical Director at Strategen. While at Strategen, I led economic and technical grid modeling engagements, including capacity expansion, production cost, and energy storage dispatch modeling. My clients included government entities and state bodies, including the Oregon Public Utility Commission, the Kentucky Public Service Commission, the Maryland Office of People’s Counsel, the South Carolina Office of Regulatory Staff, non-governmental organizations, and trade associations, as well as large energy buyers.

Before joining Strategen in 2018, I contributed to the development of analytical tools used in energy impact assessment studies. I have a Ph.D. from the Management Science and Engineering Department at Stanford University and a Master of Science in Electrical and Computer Engineering from the National Technical University of Athens, Greece.

Q. Have you previously testified before the Louisiana Public Service Commission (“LPSC” or “Commission”)?

A. No.

Q. Have you been an expert witness on resource planning matters before other regulatory commissions?

A. Yes. I have testified before state utility regulators in Colorado, Georgia, Michigan, Kentucky, Nevada, North Carolina, Oregon, South Carolina, and Virginia, while I have written comments and participated in technical workshops in a range of proceedings in Arizona, California, Colorado, Indiana, Kentucky, Michigan, Minnesota, Nevada, North Carolina, Oregon, South Carolina, Utah, and Washington. My work experience is set out in Exhibit MR-1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review and evaluate the Application of Entergy Louisiana, LLC (“ELL” or “Company”) for Approval to Construct Waterford 6 Power Station and Westlake Power Station, and for Cost Recovery (“Application”), through which ELL seeks certification of two combined-cycle combustion turbines (“CCCTs”), with a combined capacity of 1,508 MW. In doing so, I review and evaluate ELL’s stated need driving this resource procurement, the economic analysis supporting the selection of the two CCCTs and assess the impacts on ratepayers.

Q. How is your testimony organized?

A. Section II presents an overview of my main findings and recommendations. Section III provides an overview of the Application in this docket, as well as ELL’s broader proposed resource buildout. Section IV explains why, according to my review, ELL’s need analysis, or lack thereof, does not rigorously support a request of this scale. Section V addresses ELL’s procurement process and economic analysis. Section VI addresses the risks the certification of the two CCCTs poses to ratepayers, including capital cost

1 overruns and exposure to fuel price volatility. Section VII discusses a staged portfolio as
2 an alternative to ELL’s requested certification of the units. Section VIII concludes.

3 **II. Testimony Overview and Summary of Recommendations**

4 **Q. Please provide an overview of your findings.**

5 A. My primary concern in reviewing this Application is twofold: (a) the Proposed
6 Generators have not been shown to be the lowest reasonable cost resources to meet the
7 identified need, and (b) the need itself is not backed by agreements with sufficient
8 safeguards in place, meaning the risk of the load not materializing or persisting falls
9 almost entirely on existing ratepayers, exacerbating the affordability challenges they
10 already face.

11 Specifically, my findings are:

- 12 1. ELL's claimed need is not supported by a coherent analysis: the forecasted load growth
13 relies on load that might not persist and does not seem to be backed by appropriate terms
14 in service agreements, retirement dates for aging units keep shifting, and ELL has not
15 performed an optimal replacement analysis or committed to a retirement schedule. If load
16 does not materialize or persist as projected, existing ratepayers will be left paying for
17 expensive capacity they did not need in the first place.
- 18 2. No real alternative to the Proposed Generators was ever tested: the Request for Proposals
19 (“RFP”) was scoped for gas-fired CCCTs from the outset, and other resources, although
20 procured in concurrent RFPs, were never evaluated against them. Thus, the record does
21 not establish that they are the lowest reasonable cost resources.
- 22 3. ELL's own economic evaluation is methodologically flawed: the energy benefit is
23 calculated against an ELL-selected counterfactual with no analytical basis, the capacity
24 benefit rests on unproven assumptions about future need and benchmark costs, and key
25 sensitivities were never run.

1 4. Even accepting ELL's methodology, the claimed net benefits are thin and fragile: net
2 costs persist for two decades, and a likely cost increase or load shortfall erases the entire
3 projected benefit.

4 5. Certification would put substantial risk onto ratepayers. In the near term, ELL's
5 overlapping construction program exposes them to execution and capital cost-overrun
6 risk. Over the life of the units, they would bear fuel-price, supply, policy, and correlated-
7 outage risk from a more gas-concentrated fleet, plus stranded-cost risk if the load never
8 materializes, while ELL's cost-recovery structure largely insulates the Company from
9 those same risks. Because these risks fall outside the utility's control once the units are
10 committed, the Commission should address them now as part of its public interest
11 review before an irreversible commitment is made.

12 6. A staged, diversified portfolio, including energy efficiency ("EE"), demand response
13 ("DR"), storage, customer-sited resources, transmission solutions, and incremental solar
14 and storage could meet ELL's near-term need at lower cost and risk.

15 **Q. Please summarize your recommendations.**

16 A. Based on my review and analysis, I recommend the following:

17 ***Recommendation 1: No Certification at This Time***

18 The Commission should deny certification of both Waterford 6 and Westlake at this time,
19 given the deficiencies in ELL's need and economic analyses, and ELL's failure to show
20 these units are the lowest reasonable cost resources.

21 ***Recommendation 2: Conditions for Reconsideration***

22 Threshold conditions (must be satisfied before any reconsideration):

- 23 a) ELL has conducted a competitive, all-source procurement rather than relying on the
24 CCCT-only RFP;
- 25 b) the rulemaking in Docket No. R-37905 has concluded, so self-supply potential for large
26 loads is known before ELL commits ratepayers to utility-built capacity for the same load;

- 1 c) ELL has committed to firm retirement dates for Little Gypsy 2 & 3 and Nelson 6;
- 2 d) ELL has presented an updated Load and Resources analysis, reflecting the updated load,
3 but also the load flexibility customers have agreed to provide, and the projected level of
4 customer resources;
- 5 e) ELL has demonstrated pursuit of EE and DR resources at the high-adoption level
6 identified in its own demand side management (“DSM”) potential study;
- 7 f) The South Load Pocket Risk Assessment and South Long Range Transmission Planning
8 (“LRTP”) study from the Midcontinent Independent System Operator (“MISO”) are
9 completed and reflected in the record;
- 10 Supporting analyses:
- 11 g) ELL has completed its system-wide surplus interconnection capacity evaluation,
12 including the option of interconnecting energy resources at existing combustion turbine
13 (“CT”) sites;
- 14 h) ELL has presented a documented methodology for its large load forecasting (used to
15 inform the identified need in a future application), including the discount factors applied
16 at each pipeline stage, and commits to ongoing reporting to the Commission on the status
17 of that pipeline;
- 18 i) ELL has shown consideration of the impact on existing ratepayers if the large loads
19 underlying its claimed need do not materialize as forecast, documented through
20 sensitivity or other analyses in the next certification application, or has found a way to
21 contractually address that risk;
- 22 j) ELL has studied and filed a report on the role of grid enhancing technologies (“GETs”) in
23 relieving transmission constraints and the savings they could deliver.

24 ***Recommendation 3: Certification of one CCCT (If Recommendation 1 Is Not Adopted)***

25 If the Commission is inclined to certify one of the Proposed Generators now, certification
26 should be conditioned, at minimum, on ELL satisfying threshold conditions (c) and (e)

1 above: firm commitments to retire Little Gypsy 2 & 3 and Nelson 6, and committed to
2 pursue EE and DR at the high-adoption level identified in ELL's own DSM Potential
3 Study. The Commission should require all of the remaining threshold conditions, together
4 with the supporting analyses, to be satisfied before it considers certifying the second
5 Proposed Generator.

6 ***Recommendation 4: Cost Recovery Cap***

7 Independent of the above, if any of the Proposed Generators is certified, the Commission
8 should limit recovery of capital costs to a hard cap tied to the cost estimate underlying
9 certification.

10 **III. Overview of ELL's Application and Planned Buildout**

11 **A. Overview of ELL's application in the instant docket**

12 **Q. Please summarize ELL's requests in this proceeding.**

13 A. ELL is asking the Commission to approve two new gas-fired power plants: the Waterford
14 6 Power Station ("WF6") near Killona, Louisiana, and the Westlake Power Station
15 ("Westlake") in Westlake, Louisiana, with a combined capacity of 1.5 GW (collectively,
16 "Proposed Generators"). Specifically, the Company asks the Commission to:

- 17 • certify that both plants are needed and in the public interest under the 1983 General
18 Order;²
- 19 • find that the plants were selected through a competitive process that satisfies the
20 Market-Based Mechanisms ("MBM") Order;³

² General Order (Sep. 20, 1983), In re: In the Matter of the Expansion of Utility Power Plan; Proposed Certification of New Plant by the Louisiana Public Service Commission.

³ General Order (February 16, 2024), In re: Development of Market-Based Mechanisms to Evaluate Proposals to Construct or Acquire Generating Capacity to Meeting Native Load, Supplements the September 20, 1983 General Order, Docket No. R-26172 Subdocket A, (as amended by General Order, Docket No. 26172 Subdocket B, dated November 3, 2006, and further amended by the April 26, 2007 General Order and the amendments approved by the Commission at its October 15, 2008 Business and Executive Meeting; the October 29, 2008 General Order No. R-26172, Subdocket C; and the October 14, 2024 General Order No. R-34247).

- approve cost recovery for the two generating units through the Additional Capacity Mechanism (“ACM”), and recovery of the Westlake interconnection upgrades through the Transmission Recovery Mechanism (“TRM”), both under the existing Formula Rate Plan (“FRP”);⁴
- approve a Monitoring Plan with quarterly reporting on project cost and schedule;⁵ and
- act on an expedited schedule, with a decision at the Commission's December 16, 2026, Business and Executive Session, so that ELL can meet the February 2027 Final Notice to Proceed (“FNTP”) deadline needed to keep Westlake on schedule.⁶

Q. What generation and transmission facilities is ELL proposing?

A. ELL is proposing two CCCTs and associated transmission and interconnection facilities needed to bring each plant online. According to ELL, both units were selected out of ELL's 2024 CCCT RFP which solicited only combined-cycle (“CC”) gas generation. The two generating units and the related transmission facilities, with a total combined cost of \$4.1 billion, are summarized in the table below.

Table 1: Generation and transmission facilities in ELL's Application

Facility	Description	Estimated Cost ⁷	In-Service Date ⁸
WF6	754 MW 1x1 CCCT at existing Waterford site; MISO replacement-generator interconnection at Little Gypsy; WF6 Generator Tie-In	\$2,027.2 million	July 31, 2030
Westlake	754 MW 1x1 CCCT at existing Roy S. Nelson site; Westlake Generator Tie-In Westlake Interconnection Upgrades	\$2,091.0 million	Oct. 31, 2030

Q. What cost recovery mechanism is ELL requesting for these projects?

⁴ Overview of the Application at 14, section XXXI.

⁵ Overview of the Application at 17, section XXXVIII.

⁶ Direct Testimony of Michael J. Plaisance (“Plaisance Direct Testimony”), at 7:16–8:5.

⁷ Direct Testimony of Nicholas D. Pressler (“Pressler Direct Testimony”), Tables 1 & 3.

⁸ Pressler Direct Testimony, Tables 2 & 4.

1 A. ELL requests to recover the costs of WF6 and Westlake through the ACM, which
2 operates under ELL's existing FRP. Costs tied specifically to the Westlake
3 interconnection upgrades would instead be recovered through the TRM. Under this
4 approach, ELL would file a Revenue Requirement Submission for each project twelve
5 months and again sixty days before the project's in-service date, so rates can be updated
6 as each plant comes online. ELL estimates the first-year revenue requirement at
7 approximately \$244.7 million for WF6 and \$253.1 million for Westlake.⁹

8 **Q. What analysis has ELL conducted in support of this request?**

9 A. Based on my review of the Application, ELL's analytical support falls into four
10 categories:

- 11 • **Need analysis:** ELL's 2023 Final Integrated Resource Plan ("IRP") first identified
12 a growing capacity shortfall. The Company states its capacity needs have grown
13 further since that filing with its January 2026 IRP Data Filing (LPSC Docket I-
14 37764) showing an updated peak load forecast of 13,915 MW by 2030 and 14,740
15 MW by 2035.¹⁰
- 16 • **Process and cost-reasonableness analysis:** Two independent third parties
17 reviewed different aspects of the proposals themselves, rather than the need or
18 resource choice. The Independent Monitor ("IM"), Merrimack Energy Group,
19 reviewed the RFP process and concluded it was conducted fairly and in
20 compliance with the MBM Order, with no undue advantage to ELL's self-build
21 option. The Independent Engineer ("IE") Worley Consulting reviewed the self-
22 build cost estimates and found them more appropriate for a concept
23 screening/feasibility study than for a more refined estimate.¹¹
- 24 • **Resource-selection analysis:** To evaluate whether these two CCCT proposals
25 (drawn from the 2024 CCCT RFP) are the right resources to meet the identified

⁹ Direct Testimony of Patrick A. Sullivan, at 20:10 ("Sullivan Direct Testimony").

¹⁰ Plaisance Direct Testimony, at 26, n.19.

¹¹ Exhibit PDN-2, at 42.

1 need, ELL's Economic Evaluation Team (“EET”) ran an economic evaluation
2 using the AURORA production cost model. This found a positive net present
3 value (“NPV”) for both Westlake [REDACTED] and WF6 [REDACTED], [REDACTED]
4 [REDACTED].¹² An
5 updated analysis using revised project costs shows positive but significantly lower
6 net benefits (Westlake: [REDACTED], WF6: [REDACTED]).¹³

- 7 • **Ratepayer impact analysis:** ELL's Regulatory Affairs witness (Sullivan)
8 calculated the projected revenue requirement and bill impact of the two projects:
9 an estimated first-year revenue requirement of \$244.7M¹⁴ (WF6) and \$253.1M¹⁵
10 (Westlake), and a combined residential bill impact of about \$14.37/month for a
11 1,000 kWh/month customer.¹⁶ ELL also frames this against a projected net
12 customer benefit of roughly [REDACTED].¹⁷

13 I have concerns about the robustness and results of each of these analyses, which I
14 discuss in Sections IV and V below.

15 **B. ELL’s other pending and recently approved resource requests**

16 **Q. Before outlining your concerns about ELL's need and economic analyses in this**
17 **docket, can you please provide information on the magnitude of “all currently**
18 **pending and approved resources” that ELL has requested Commission approval**
19 **for?**

20 **A.** Yes. While my review of the Application is independent of ELL's requests in other
21 dockets, and I find that the Proposed Generators in this proceeding introduce substantial
22 risk for ratepayers on their own terms, it is important to contextualize this request as part
23 of ELL’s much larger requested buildout. The scale of this cumulative buildout across
24 multiple dockets, and the significant concentration of that buildout in gas-fired

¹² Direct Testimony of Phong D. Nguyen ("Nguyen Direct Testimony"), at 16:14–17:13.

¹³ Nguyen Direct Testimony, at 18:8.

¹⁴ Sullivan Direct Testimony, at 20:7.

¹⁵ Sullivan Direct Testimony, at 20:9.

¹⁶ Sullivan Direct Testimony, at 20:17.

¹⁷ Sullivan Direct Testimony, at 36:15–18.

1 generation, result in an overall system risk that is higher than that of each individual
2 component.

3 Across the dockets currently before the Commission or recently approved, ELL's planned
4 capacity additions include:

- 5 • **Instant docket (U-37853):** application to construct two 754 MW CCCT units
6 (WF6 and Westlake), totaling 1,508 MW, with projected in-service dates in 2030
7 (pending);
- 8 • **U-37801:** application to acquire the Cottonwood generating facility, an
9 approximately 1,263 MW CCCT (pending);¹⁸
- 10 • **U-37872:** purchase agreements for the Oxy Taft, Big Cajun 1, and Bayou Cove
11 gas resources, plus the Zydeco Solar capacity credit purchase agreement
12 (pending);¹⁹
- 13 • **U-37193:** capacity credit purchase agreement for 290 MW of capacity-related
14 benefits from the Magnolia Power Generating Station, an approximately 700 MW
15 CCCT;²⁰
- 16 • **U-37425:** three new 754 MW CCCTs (Franklin Farms 1, Franklin Farms 2, and
17 Waterford 5) and 1,500 MW of solar and/or solar plus storage battery resource,
18 approved in connection with the Laidley/Meta project;²¹

¹⁸ LPSC Docket No. U-37801, *In re: Application of Entergy Louisiana, LLC for Approval to Acquire Cottonwood Generation Facility and for Cost Recovery* (approximately 1,263 MW (nominal) CCCT; pending).

<https://lpscpubvalence.lpsc.louisiana.gov/portal/PSC/DocketDetails?docketId=32621>

¹⁹ LPSC Docket No. U-37872, *In re: Application of Entergy Louisiana, LLC for Approvals Relating to Various Purchase Agreements, and for Associated Cost Recovery*.

²⁰ LPSC Docket No. U-37193, *In re: Application for Approval of the Magnolia Capacity Credit Purchase Agreement, Cost Recovery, and Related Relief* (Commission-approved capacity credit purchase agreement for 290 MW of CCGT capacity-related benefits from the Magnolia Power Generating Station).

<https://lpscpubvalence.lpsc.louisiana.gov/portal/PSC/DocketDetails?docketId=31782>

CCGT stands for Combined Cycle Gas Turbine and refers to the same technology as CCCT.

²¹ LPSC Order No. U-37425, *In re: Application for Approval of Generation and Transmission Resources in Connection with Service to a Single Customer for a Project in North Louisiana* (approving, per settlement accepted at the Commission's Aug. 20, 2025 B&E Session, three CCCT generators: the two Franklin Farms Power Station units in Richland Parish and a third 754 MW unit at ELL's Waterford site plus associated transmission).

<https://lpscpubvalence.lpsc.louisiana.gov/portal/PSC/DocketDetails?docketId=32146>

- 1 • **U-37882:** seven new 754 MW CCCT units (approximately 5.3 GW), three battery
2 storage facilities, and associated transmission, in connection with service to
3 Project Evest, Meta's expanded data center development (pending);²²
- 4 • **U-37800:** application to construct the Votaw (approximately 141 MW AC) and
5 Segno solar facilities (pending);²³
- 6 • **U-36697:** ELL's "3 GW filing," a process to secure up to 3,000 MW of solar
7 resources, with certifications ongoing under the 3 GW Order (approved;
8 certifications ongoing);²⁴
- 9 • **U-37071** the 2023 Solar Application, including the power purchase agreement for
10 the Mondu Solar Facility (approved);²⁵ and
- 11 • **U-37595:** Demand Response Programs and cost recovery application, which is
12 explicitly excluded from the load and capability figures cited in this Application
13 (approved).^{26,27}

14 In addition, the Company is pursuing the development of significant transmission
15 projects to support load growth and economic development in southeast Louisiana.²⁸

16 Figure 1 presents ELL's existing and planned resources as included in its most recent
17 resource analysis, presented in docket U-37882.²⁹ The figure shows that ELL plans to

²² LPSC Docket No. U-37882, *In re: Application of Entergy Louisiana, LLC for Approval of Investments Proposed in Connection with Service to Project Evest* (seven new 754 MW CCCT generators, three battery storage facilities, and a new 150-mile 500 kV line from Richland Parish to St. Landry Parish; pending).

²³ LPSC Docket No. U-37800, *In re: Application of Entergy Louisiana, LLC for Approval to Construct the Votaw and Segno Solar Facilities, and for Cost Recovery* (filed Dec. 1, 2025).

²⁴ LPSC Docket No. U-36697, *Ex Parte: Application of Entergy Louisiana, LLC for Approval of Alternative Process to Secure up to 3,000 MW of Solar Resources, Certification of those Resources, Expansion of the Geaux Green Option, Approval of a New Renewable Tariff, and Related Relief*.

²⁵ Order No. U-37071, *In re: Application for Approval of the Mondu Solar Power Purchase Agreement, Expansion of the Geaux Green Tariff, and Cost Recovery* (application filed Dec. 18, 2023; approved).

²⁶ Plaisance Direct Testimony at 32, n.33.

²⁷ Order No. U-37595, *In re: Application of Entergy Louisiana, LLC for Approval of Demand Response Programs and Associated Cost Recovery*, LPSC Docket No. U-37595 (Apr. 17, 2026) (accepting the uncontested stipulated settlement filed February 9, 2026; effective immediately).

²⁸ Plaisance Direct Testimony, Table 1.

²⁹ ELL response to Staff I-94, attachment "Staff I-94 BP26 and Evest L&Cs_HSPM." [REDACTED]

1 double its system size (expressed in Summer Accredited Capacity (“SAC”)) within the
2 next six years (2026-2032), with the vast majority of those additions consisting of gas-
3 fired resources.

4 [REDACTED]

5 [REDACTED]

6 The scale and gas-concentration of this broader buildout directly affect the risks the
7 proposed generators pose to ratepayers, as I will discuss in Section VI.

8 **IV. ELL's Need Analysis, or Lack Thereof, Does Not Support A Request of This**
9 **Scale.**

10 **Q. According to ELL, what is driving the resource need?**

11 A. ELL states that its system faces a substantial and growing capacity shortfall and
12 attributes this to two main drivers:

- 13 1. Anticipated load growth: The Company's capacity needs have grown since its
14 2023 Final Integrated Resource Plan, filed in LPSC Docket No. I-36181 and

[REDACTED]

acknowledged by the Commission on February 21, 2024 (the “2023 IRP”). The growth is driven substantially by new industrial and economic development load, including a Hyundai steel mill, a CF Industries ammonia facility, and a Woodside LNG facility.³⁰ These three customers correspond to three anonymized projects in its planning data, with maximum demand of [REDACTED], respectively, for a combined [REDACTED].³¹

2. Anticipated reduction in the existing system’s capacity: ELL is evaluating operations at Little Gypsy Units 2 and 3 and Nelson Unit 6, which if retired, will reduce the system’s existing capacity.³²

ELL quantifies the projected shortfall using MISO's Summer SAC construct, a seasonal resource-adequacy accreditation methodology MISO adopted beginning with the 2023-2024 Planning Year,³³ showing a need in excess of [REDACTED], even after accounting for all currently pending and approved resources.³⁴ ELL further points to tightening capacity market conditions in MISO's Local Resource Zone 9 (“LRZ 9”) to underscore the urgency of this case.

Q. What are your main concerns with respect to ELL’s claimed need and analysis?

A. Although the Application heavily references recent industrial load growth as the driver of the need for the Proposed Generators, neither the 2024 CCCT RFP nor the economic evaluation of the units was based on BP26, the forecast that actually incorporates that growth. BP26 is referenced in this Application to create a sense of urgency that is neither fully supported by the underlying load data (as I explain in Section IV.A) nor shown to require the Proposed Generators in the supply plan (as I explain in Section IV.C).³⁵

³⁰ Plaisance Direct Testimony at 34: 8-13.

³¹ ELL Response to Southern Renewable Energy Association (“SREA”) 1-7.

³² Plaisance Direct Testimony, at 18:20–19:7.

³³ Plaisance Direct Testimony, at 29:11.

³⁴ Plaisance Direct Testimony, at 33:10–11.

³⁵ ELL response to EDF 1-5 states: “Notably, BP26 was used in preparing the supply plan, as reflected in the Direct Testimony of Michael J. Plaisance.”

1 The second stated driver is the potential reduction in existing capacity from the
2 deactivation of aging units. However, ELL does not commit to any retirement date;
3 deactivation dates and conversion assumptions keep shifting across ELL's own analyses
4 and workpapers (see Section IV.C). Furthermore, ELL has not produced any analysis
5 showing that the Proposed Generators are the optimal or lowest reasonable cost
6 replacement for those units, as opposed to a different resource portfolio.

7 In short, there is no single, internally consistent, let alone rigorous, analysis behind the
8 need for these units. ELL's claimed need does not read as a starting point for this
9 Application, but as an afterthought assembled to support resources ELL had already
10 decided to build.

11 **Q. ELL claims a remaining need even after accounting for its other approved and**
12 **pending additions.³⁶ Do you find this convincing?**

13 A. No. ELL states that, given industrial load growth, it has a remaining need even after all
14 approved and pending additions. That claim rests on BP26. As I explain below, BP26
15 itself is not well supported. And even taking BP26 at face value, I show in Section VII
16 that ELL has alternative options that would meet that need without the same risks and
17 costs, options ELL never tested.

18 **Q. Why do you say BP26 is not well supported?**

19 A. First, ELL has not provided a well-documented methodology for incorporating large load
20 requests into its BP26 forecast and has not produced any analysis or workpaper
21 reconciling the substantial increase between its Business Plan 2022 (“BP22”) forecast
22 (the basis for the 2023 Final IRP) and BP26. ELL's workpapers and discovery responses
23 do not document a clear methodology, including how that pipeline has evolved over time,
24 and thus it is unclear whether ELL has adequately accounted for the risk that new load
25 will not commit, materialize, or persist as forecast. Furthermore, ELL has not produced
26 the underlying service agreements or described their general terms, has not shown what

³⁶ Plaisance Direct Testimony, at 33:9-11.

discount it applied for the risk of delay or non-materialization, and has performed no sensitivity analysis testing how its claimed need would change if these loads materialize differently than assumed. Additionally, ELL has not shown that it accounted for the shorter contract terms of these customers relative to the life of the incremental infrastructure, or for the load flexibility and self-supply they may bring. This risk is especially significant given how concentrated ELL's claimed load growth is in a small number of very large customers, such that the non-materialization of even one could eliminate a substantial share of the claimed need.

I explain in detail each of those concerns below.

A. ELL has not produced a coherent analysis or methodology substantiating the claimed load growth.

Q. How does ELL's BP26 load forecast differ from the BP22?

A. The BP22 forecast underlying the 2023 IRP projected a 2030 summer coincident peak of 10,224 MW.³⁷ ELL's BP26 forecast shows 13,915 MW in 2030,³⁸ i.e. an increase of 3,691 MW, or about 36 percent. The same pattern holds in winter, with BP26 indicating a coincident peak of [REDACTED] MW in 2030,³⁹ while BP22 was projecting a 9,367 MW peak,⁴⁰ resulting in a delta of [REDACTED] MW or a [REDACTED] percent increase. The increase, however, is significantly more pronounced for the energy forecast: BP26 projects an annual energy forecast of [REDACTED] GWh⁴¹ versus [REDACTED] GWh in BP22,⁴² i.e. [REDACTED] GWh or a [REDACTED] percent increase. Figure 2 shows the summer and winter MISO coincident peak levels for BP22 and BP26. Figure 3 shows the corresponding energy forecasts.

³⁷ 2023 IRP, Table 40: Summer Coincident Peaks (MW) Forecast.

³⁸ Plaisance Direct Testimony, at 26, footnote 19.

³⁹ ELL response to Sierra 1-1, attachment "Exhibit MJP-1 BP26 Final L&Cs w Chart_HSPM."

⁴⁰ 2023 IRP, Table 41: Winter Coincident Peaks (MW) Forecast.

⁴¹ ELL response to Sierra 1-4, attachment "RL-U37853-00SIE001-L004_HSPM."

⁴² ELL response to Sierra 1-25, attachment "2023 ELL Integrated Resource Plan Final Report_HSPM, Table 39: Annual Energy Forecasts (GWh)."

1

[REDACTED]

[REDACTED]

2

3

4

[REDACTED]

[REDACTED]

5

6 **Q. Has ELL provided an analysis reconciling this increase?**

7 A. No. There is no analysis or workpaper in the record that clearly reconciles the BP22-to-
8 BP26 increase. When asked to provide such an analysis, ELL objected, stating:

9 The Company objects to the request to the extent it seeks an exhaustive listing of
10 each of the referenced differences and to the extent it seeks information that is
11 equally available to the requester based on review of available documents. Subject
12 to and without waiving the foregoing, the largest single driver of differences of
13 MWh volumes in the two forecasts is the new, large industrial customers in BP26.
14 These types of customers, along with the change concerning wholesale energy

1 from BP22 (which is now part of the retail industrial energy), comprise 95-100%
2 of the energy differences between the two forecasts.⁴³

3 **Q. Has ELL previously outlined a methodology for large load additions?**

4 A. To a limited degree. ELL's 2023 IRP states that large industrial customers are forecast
5 individually, not as part of a broader class trend, and that forecasts for new large
6 customers are risk-adjusted based on each customer's progress toward achieving
7 commercial operation, meaning industrial load additions are treated as incremental,
8 customer-specific items subject to an explicit discount for uncertainty.⁴⁴

9 **Q. Has ELL followed this methodology in preparing the BP26 load forecast?**

10 A. It is unclear. ELL claims that the industrial loads are included in BP26 on a probability-
11 weighted basis but has not provided any analysis showing how the probabilities were
12 estimated and applied.⁴⁵ Absent that, there is no way to confirm that BP26 reflects the
13 same risk-adjustment discipline ELL says it applies generally.

14 **Q. How do the incremental loads in ELL's pipeline compare to the projected BP22-to-
15 BP26 gap?**

16 A. Including the projected load ramp for all industrial customers included in the BP26
17 forecast, the total falls short of the incremental load implied by the increase in energy
18 required between BP22 and BP26.⁴⁶ Figure 4 shows the pipeline load adjusted for
19 contract term, using the contract terms ELL provided as of July 13, 2026, for each
20 industrial load (that is, each load is included only for the number of years it has a signed
21 contract).

⁴³ ELL response to EDF 1-3.

⁴⁴ 2023 IRP at 50.

⁴⁵ ELL response to EDF 1-9.

⁴⁶ As of July 14, 2026, only [REDACTED] did not have a signed ESA. [REDACTED] has a projected load of [REDACTED] and if included in the graph, it would not change the conclusions.

1 [REDACTED] ⁴⁷

2 [REDACTED]

3 [REDACTED]

4 Even under the assumption that all customers renew their contracts, the gap between the
5 pipeline and the BP26 industrial load forecast keeps growing. That concern is only
6 heightened when considered alongside the multi-decade depreciation life of the Proposed
7 Generators, and the fact that ELL's projected net benefits grow over time (see Section
8 V.B.3) based on an energy and capacity need that itself lacks a documented basis.

9 [REDACTED] ⁴⁸

⁴⁷ Industrial Load Pipeline (adjusted for term): ELL response to Sierra 2-8, attachment “RL-U37853-00SIE002-L008_PART_A_HSPM,” adjusted based on terms provided in ELL response to Sierra 3-11, attachment ‘RL-U37853-00SIE003-L011_PART_A_HSPM_MW_Update (without customer names) HSPM.’ [REDACTED]

Industrial Load Growth: ELL response to EDF 1-3, attachment “RL-U37853-00EDF001-L003_ab_HSPM,” comparison of industrial class forecasts in tabs “BP22 Class Energy” and “BP26 Class Energy.”

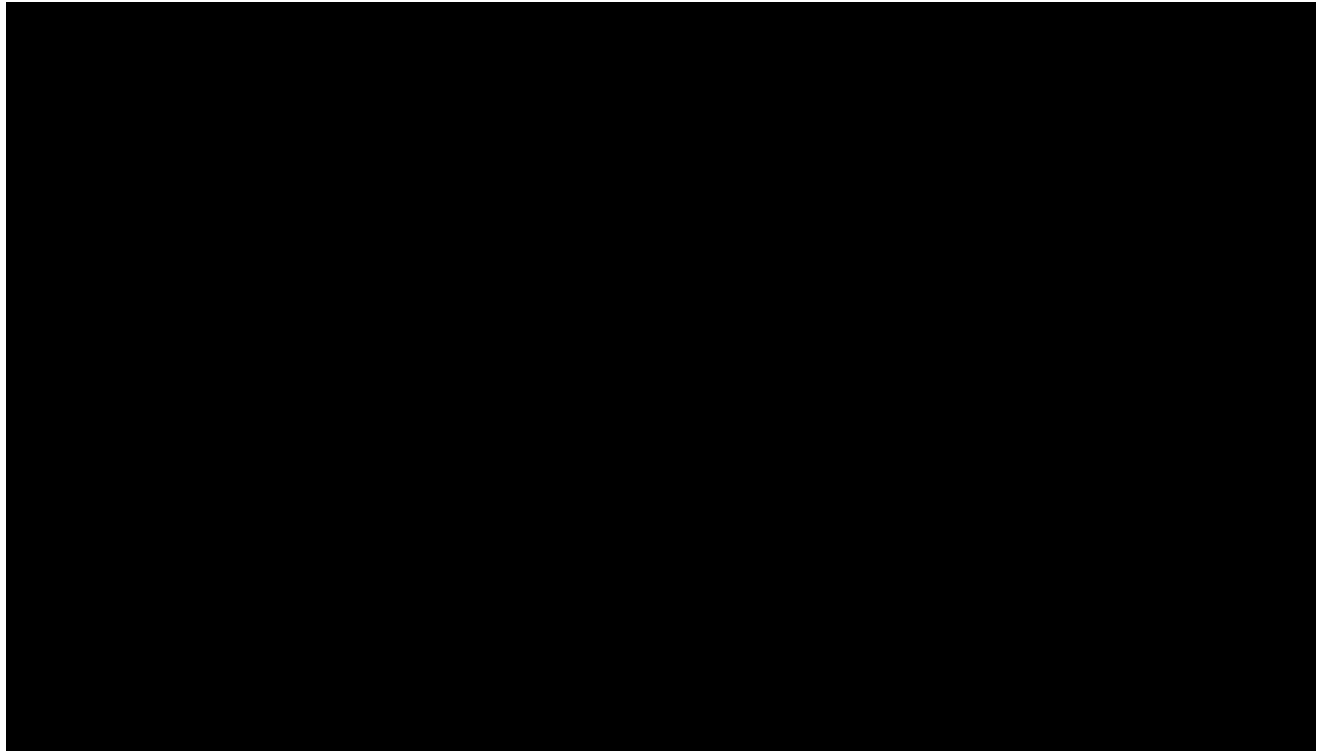
⁴⁸ Industrial Load Pipeline (adjusted for term): ELL response to Sierra 3-11, attachment ‘RL-U37853-00SIE003-L011_PART_A_HSPM_MW_Update (without customer names) HSPM.’ [REDACTED]

The average demand is based on the expected load factor as calculated based on attachment ELL response to Sierra 2-8, attachment “RL-U37853-00SIE002-L008_PART_A_HSPM.”

Industrial Load Growth: ELL response to EDF 1-3, attachment “RL-U37853-00EDF001-L003_ab_HSPM,” comparison of industrial class forecasts in tabs “BP22 Class Peaks” and “BP26 Class Peaks.”

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3

4 The comparison in terms of demand is more difficult to interpret, since industrial loads
5 will not necessarily all peak at the same time. Data center load, which makes up much of
6 the load shown in this graph, and much of the industrial load, is actually projected to stay
7 at a relatively consistent level around the clock — close to its average level, rather than
8 showing a sharp peak.⁴⁹ Figure 5 presents the projected growth in peak demand of the
9 industrial segment in the BP26 forecast compared to BP22, alongside the industrial load
10 pipeline: the dark grey reflects average demand (calculated using the load ramp as
11 included in BP26),⁵⁰ while the lighter grey shows peak demand for all customers if their
12 undiscounted peaks were to coincide.

⁴⁹ Plaisance Direct Testimony, at 46:13-14, “including high-load factor industrial customers whose energy usage remains at a largely consistent level around the clock.”

⁵⁰ ELL response to EDF 1-9 specifies that the Sierra 2-8 attachment includes the projected load ramp reflected as annual MWh included in the BP26 forecast on a probability-weighted basis.

B. Relying on concentrated, correlated, short-term industrial load to inform long-term planning creates risks for existing ratepayers.

Q. Do you have other concerns about how ELL incorporated the industrial load in its forecast to inform its resource needs?

A. Yes. An ESA does not establish that the load will show up as forecast. It also does not justify committing ratepayers to thirty-year, large-scale generating assets on that basis alone. There are several circumstances that could result in lower load materialization. In addition to probability weights, the assumed commitment should be paired with scenario testing of how the claimed need could change, along with a deeper understanding of the drivers, correlations, and other parameters underlying it. Importantly, ELL should also assess how other ratepayers would be affected in the event of lower load growth, and what protections would be available to them. ELL has not produced any sensitivity analysis around load materialization or analysis on ratepayer impacts under such a scenario.⁵¹

Specifically, I discuss four concerns that remain even if loads have ESAs and the load growth reflected only those:

- First, even when a customer has signed an ESA, that does not necessarily mean the load will show up as projected, particularly absent a strong financial commitment.
- Second, even where a customer has signed an Electric Service Agreement (“ESA”), the term of that commitment is [REDACTED] than the life of the assets being built to serve it, [REDACTED]
- Third, even if a load does show up, there are elements that could reduce its impact on the claimed need, most notably customer load flexibility and customer programs, that ELL has not properly accounted for in its analysis.

⁵¹ ELL response to Staff 1-94(g).

- Fourth, even if the large majority of these loads show up as forecasted, the non-materialization of even one is significant, given how concentrated ELL's claimed growth is in a small number of very large loads.

These four concerns point to the same underlying gap: the fact that ELL has executed an ESA does not mean other ratepayers are protected, since the terms have not been produced in the record. Specifically, ELL has not shown that it has pursued or implemented a contractual framework that would address the risks to other ratepayers. ELL does not appear to have meaningfully considered those issues, leaving residential and other existing ratepayers exposed.

Q. Turning to your first concern, have you been able to review the executed ESAs for the industrial customers discussed above, or otherwise confirm whether these customers have made any financial commitments or have any minimum-demand obligations that would limit this risk?

A. No. ELL has objected to producing the actual ESAs in discovery, citing confidentiality and competitive-harm concerns, and has not provided them to date.⁵² Even setting aside the ESAs themselves, ELL did not describe any terms of these agreements (e.g. minimum demand, termination penalties, or other contractual requirements), even when this could be done without disclosing customer-identifying or confidential details. As a result, the record does not establish whether these customers have made any financial commitment sufficient to treat their anticipated load as a credible basis for capacity planning, or whether they could reduce or discontinue that load with limited financial consequence to themselves.

Q. Is there evidence that some of these loads may materialize more slowly than forecast?

⁵² ELL response to EDF 1-2.

1 A. Yes. In my experience from reviewing economic development and large load pipelines,
2 large loads of this kind can experience schedule slippage in the near term, particularly
3 absent guardrails such as a financial or minimum-demand commitment.

4 For example, Staff 1-94's pipeline data shows several projects [REDACTED]
5 [REDACTED] forecast to reach full load by 2026 yet
6 still not reflected as "Completed." That gap is at least consistent with the possibility that
7 these loads will not reach the forecasted level on schedule, though I recognize that
8 pipeline stage data reflects a snapshot in time and some of these projects may have since
9 advanced, others may have been delayed further.

10 More broadly, ELL's own forecast shows that [REDACTED]
11 [REDACTED] despite the
12 forecasted growth.⁵³

13 **Q. Do you have a recommendation for how the Commission could better track the**
14 **pipeline and understand its evolution?**

15 A. Yes. Regular reporting would help the Commission track the development of ELL's
16 large-load pipeline over time and build a shared understanding of how this relatively new
17 customer class behaves, since ELL, like other utilities, is still gaining experience
18 forecasting and serving load of this scale and speed. To my knowledge, ELL does not
19 currently provide the Commission with a documented forecasting methodology,
20 including the discount factors it applies at each stage of the pipeline. Other jurisdictions
21 have adopted this kind of ongoing reporting as this large-load customer class has grown
22 more prominent. In North Carolina, the Utilities Commission directed Duke Energy to
23 monitor its pipeline of large-load additions of 20 MW or more and file semiannual
24 reports addressing changes to proposed large-load additions in advanced development.⁵⁴
25 Georgia's Public Service Commission similarly requires Georgia Power to file quarterly

⁵³ 2023 IRP at 172, Table 40: Summer Coincident Peaks (MW); ELL response to Sierra 1-1, "Exhibit MJP-1 BP26 Final L&Cs w Chart_HSPM," "ELL L&C" tab.

⁵⁴ North Carolina Utilities Commission, Order Accepting Stipulation, Granting Partial Waiver of Commission Rule R8-60A(d)(4), and Providing Further Direction for Future Planning, Docket No. E-100, Sub 190 (Nov. 1, 2024), available at <https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=9cc9028d-feac-458e-8cb4-6e28fc7756f5>

1 large-load reports providing regular updates on forecasted growth and electrical
2 demand.⁵⁵ A comparable requirement here would give the Commission ongoing visibility
3 into how ELL's large-load pipeline is developing and a better understanding of what to
4 expect from this type of load in the longer term, and how it should inform the load
5 forecast and, consequently, resource planning.

6 **Q. With respect to your second concern, what is a typical term for such an ESA and**
7 **why is this information relevant?**

8 A. ELL's response to Sierra 3-11 shows several projects with ESA terms of [REDACTED].⁵⁶ [REDACTED]
9 [REDACTED]
10 [REDACTED].⁵⁷ Despite this, ELL's forecast of the industrial load, as shown
11 through the BP22-to-BP26 divergence, continues to grow well beyond the contract terms
12 of any of the customers identified without consideration that the underlying customer
13 commitments driving that growth do not extend far enough into the future to support it.
14 I recognize that a customer might not want to sign a [REDACTED]-year service agreement, because
15 doing so would mean bearing that risk itself. Without such a commitment, that same risk
16 is instead shifted to existing ratepayers. A [REDACTED] commitment does not adequately
17 protect the rest of ELL's ratepayers when that same customer's anticipated load is being
18 used to justify a capacity addition sized to serve it⁵⁸ and recovered from all ratepayers
19 over [REDACTED].⁵⁹ At a minimum, there should be some demonstrated consideration of
20 the long-term implications of relying on these shorter-term commitments.

21 **Q. Given many of those customers with [REDACTED] term ESAs are industrial customers,**
22 **would it not be reasonable to assume they will renew at the end of their term?**

⁵⁵ Georgia Public Service Commission, Order Adopting Stipulated Agreement, Georgia Power Co.'s 2023 IRP Update, Docket No. 55378 (Apr. 16, 2024), available at <https://psc.ga.gov/search/facts-document/?documentId=218484>

⁵⁶ ELL response to Sierra 3-11.

⁵⁷ Exhibit PDN-2, at 51.

⁵⁸ ELL acknowledges that 95-100% of the growth in energy needs in BP26 relative to BP22 comes from industrial customers. ELL response to EDF 1-3.

⁵⁹ Exhibit PDN-2, at 51 notes that: "ELL typically assumes a 30-year useful life for CCCT technology."

1 A. Not necessarily. Even if a customer's need for power continues, nothing guarantees it
2 continues at the original ESA level, or that ELL keeps serving it in its entirety. A
3 customer whose actual needs come in lower would renew at that lower level. This
4 uncertainty is particularly acute for load that has only appeared in ELL's forecast within
5 the last few years, without significant empirical data on how it might evolve. But even a
6 customer whose needs stay as originally projected could still choose, at renewal, to meet
7 some of that need through customer resources (particularly if doing so can result in
8 savings compared to full reliance on ELL's gas-heavy generation), depending on the
9 outcome of the concurrent rulemaking in Docket No. R-37905, discussed in Section
10 V.B.3 below. ELL's own Geaux Green Option shows substantial waitlisted demand from
11 large customers seeking clean energy arrangements beyond what ELL currently provides,
12 as discussed below in Section VII.B.5, indicating that at least some industrial customers
13 may seek to restructure how their load is served, including through cleaner or self-
14 supplied resources, once their current ESA term ends.

15 So while industrial load, once it has actually materialized, is not likely to simply vanish
16 within a few years, that is different from assuming it keeps being served by ELL at the
17 forecast level.

18 **Q. Please elaborate on your third concern, that elements of those large loads have not**
19 **been accounted for, potentially inflating the claimed need.**

20 A. ELL appears to have included these loads in its analysis asymmetrically: counting their
21 demand toward total load but not showing any corresponding increase in capacity-side
22 credit for any flexibility they can provide. ELL's response to Sierra 1-6 discloses, for
23 each customer, a simple yes-or-no indicator of whether load flexibility exists: [REDACTED]
24 [REDACTED]⁶⁰ but ELL does not disclose what that flexibility
25 consists of: the amount of load involved, the conditions under which it would be
26 dispatched, or how, if at all, it is reflected in ELL's resource-adequacy or production-cost
27 modeling. Separately, in response to Sierra 1-6(b), ELL objected to describing the type

⁶⁰ ELL response to Sierra 1-6.

1 and capacity of any self-supply resources these customers may bring on-site,
2 characterizing that information as irrelevant and objectionable.⁶¹

3 This matters because ELL's analysis shows that Load Modifying Resources ("LMRs"),
4 which reflect the capacity credit associated with interruptible and demand-response
5 programs, are assumed to remain static throughout the entire study period⁶² even though
6 the IRP itself acknowledges that "[a]s customers enroll in these new tariffs, the
7 Company's portfolio of LMRs may increase."⁶³ Despite that acknowledgment, and
8 despite some of the large new industrial customers [REDACTED]

9 [REDACTED]

10 [REDACTED]

11 [REDACTED]

12 As a result, while the record confirms that at least some of these customers have
13 flexibility commitments in place, this is not considered in ELL's projected system
14 needs.⁶⁴

15 **Q. Please elaborate on your fourth concern, the outsized impact that a change in even**
16 **one customer's load could have.**

17 A. In cases in which resource additions are driven by a few large load customers, load
18 materialization risk is a function of two things: the uncertainty in whether the load will
19 actually materialize as forecast and persist for the full life of the assets built to serve it,
20 and the consequential impact if it does not. In this case, the need underlying this buildout
21 rests on a limited number of large, discrete industrial loads, rather than the gradual, load
22 growth spread across the entire residential, commercial, and industrial base utilities
23 typically plan around. The realization or cancellation of even one such load can
24 materially change system needs and the optimality of ELL's resource portfolio in a way
25 that gradual load growth would not. For example, [REDACTED]

⁶¹ ELL response to Sierra 1-6(b).

⁶² ELL response to Sierra 1-1, "Exhibit MJP-1 BP26 Final L&Cs w Chart_HSPM," "ELL L&C" tab.

⁶³ 2023 IRP at 23.

⁶⁴ Sierra 1-1 Exhibit MJP-1 BP26 Final L&Cs w Chart_HSPM.

1 [REDACTED],⁶⁵ representing a substantial share of
2 ELL's claimed capacity shortfall on its own.

3 If ELL does not account for these risks when signing ESAs and planning additional
4 capacity, and one or more of these large loads does not materialize as assumed, other
5 ratepayers bear the cost of that capacity, not the customers whose anticipated load
6 justified the investment, and not ELL or its shareholders.

7 This risk is compounded by the fact that it is correlated, both within ELL's own portfolio
8 and with the broader buildout across the MISO market. Other resource additions in the
9 region, and in the broader MISO footprint, are being driven by similar anticipated
10 industrial and data center load, which depends to some degree on the same underlying
11 regional economic factors, meaning several commitments could be affected at the same
12 time. If that load fails to materialize as forecast, MISO as a whole could end up with a
13 surplus, since neighboring utilities and generators are responding to the same overlapping
14 load assumptions. That matters because ELL's ability to sell excess capacity into the
15 market (and avoid potential stranded assets concerns) is weaker if the whole region is
16 simultaneously in the same position. In that scenario, again, ELL's ratepayers would be
17 left holding stranded capacity with no ready way to mitigate that exposure.

18 **Q. Please elaborate on your concern that ELL is not considering or hedging against**
19 **risks for other ratepayers at the level required.**

20 A. Taken as a whole, these four concerns point to the same underlying gap: the fact that ELL
21 has executed an ESA does not mean other ratepayers are protected. To my knowledge,
22 ELL has not provided its actual ESAs for review to confirm what protections, if any, they
23 contain, has not provided a template ESA, and has not identified, for each customer, the
24 specific schedule or tariff under which it will take service, or provided details on any
25 other terms of its agreement with ELL.⁶⁶ In other jurisdictions, loads above a certain
26 threshold (for example, above 30 or 50 MW) are subject to large load tariffs that address

⁶⁵ Plaisance Direct Testimony, at 4:11–12; ELL response to SREA 1-7.

⁶⁶ ELL response to EDF 1-8.

1 these risks in a transparent and consistent way.⁶⁷ financial commitments that respond to
2 my first concern, minimum years of commitment that respond to my second, and load-
3 flexibility provisions that respond to my third. My fourth concern, concentration risk, is
4 not fully solved by a tariff alone, but minimum-demand terms would at least limit how
5 much of that risk falls on other ratepayers if one of these large commitments doesn't hold.
6 ELL's own large-load tariffs, Schedule LPHLF-G (Large Power High Load Factor
7 Service) and Schedule LLHLFPS-L (Large Load, High Load Factor Power Service), do
8 not appear to fully address these concerns, leaving a gap even where a customer is served
9 under one of them.

10 Of the [REDACTED] MW of industrial load in ELL's pipeline, [REDACTED] MW is under individual
11 contracts each above 100 MW, a scale consequential enough to drive real changes in
12 resource planning and incremental resource procurement.⁶⁸ These customers, however,
13 have contract terms of [REDACTED] years, with the majority on the shorter side, far short of the
14 life of the incremental capacity built to serve them. ELL is not hedging against these risks
15 at the level this magnitude of investment requires, and that gap shifts risk onto residential
16 and other existing ratepayers in a way that should not be acceptable.

17 **Q. Has ELL performed any sensitivity analysis testing how its claimed need would**
18 **change if these loads perform differently than forecast?**

19 A. No. ELL was asked in discovery whether it had performed any scenario analyses or
20 sensitivity analyses related to the inclusion of certain loads, which ELL denied. ELL's
21 claimed need is based on a single case, with no demonstrated assessment of how that
22 need, or the risk borne by ratepayers, would change if these loads materialize differently
23 than assumed.⁶⁹ That is a significant gap in a request of this scale and cost.

⁶⁷ Edison Electric Institute, "Large Load Projects and Tariffs" (June 2026), available at <https://www.eei.org/-/media/Project/EEI/Documents/Issues%20and%20Policy/List%20of%20Large%20Customer%20Projects%20and%20Tariffs>.

⁶⁸ ELL response to Sierra 3-11, attachment 'RL-U37853-00SIE003-L011_PART_A_HSPM_MW_Update (without customer names) HSPM.'

⁶⁹ ELL response to Staff 1-94(g).

1 **Q. Has ELL performed any sensitivity analysis to quantify the bill impact for other**
2 **ratepayers of serving the industrial load growth?**

3 A. When asked in discovery, ELL responded that it has not conducted any analysis to
4 quantify the bill impacts from specific load requests and that it does not calculate the bill
5 impacts for other ratepayers to serve a particular customer on an individual basis. ELL
6 further adds that its line extension policy under its Terms and Conditions filed with the
7 LPSC “serves to ensure that provision of service to new customers does not unduly
8 burden its existing ratepayers.”⁷⁰ However, ELL has estimated that the residential
9 customer using 1,000 kWh per month is expected to experience a first-year bill increase
10 of approximately \$14.37 per month as a result of the Proposed Generators: \$7.06 of this
11 amount attributable to WF6, and \$7.30 attributable to Westlake.⁷¹ To the extent that the
12 Proposed Generators are the result of industrial load growth, as ELL asserts in the
13 Application, there should be consideration as to how their costs are allocated, as well as
14 protections for residential and other existing ratepayers if that load does not materialize.

15 **C. ELL has neither committed to the retirements underlying its claimed need, nor**
16 **determined the optimal replacement resources.**

17 **Q. According to the Application, ELL's need is also linked to the retirement of several**
18 **legacy units. Do you find that convincing?**

19 A. No. ELL points to the potential deactivation of Little Gypsy 2 & 3 and Nelson 6 as part
20 of the capacity shortfall that creates a need for the Proposed Generators.⁷² However, ELL
21 has not presented an optimal retirement or replacement analysis, nor has it committed to
22 actually retiring either unit.⁷³ Furthermore, the Little Gypsy units operate as peaking
23 resources, and their retirement would not necessarily create an energy gap requiring new
24 baseload resources.

⁷⁰ ELL response to EDF 1-12.

⁷¹ Sullivan Direct Testimony, at 20:16-19.

⁷² Plaisance Direct Testimony, at 18:21-19:7.

⁷³ Plaisance Direct Testimony, at 20:5-7.

1 **Q. Has ELL conducted an analysis to determine the optimal timing or replacement for**
2 **those units?**

3 A. No; at least not as part of this Application. Decisions of this kind are typically evaluated
4 through a dedicated retirement analysis, or within a broader capacity expansion study
5 such as an IRP, to determine if and when a unit should optimally be deactivated and what
6 the appropriate replacement resource portfolio would be.

7 Specifically, ELL has not evaluated other options that could more effectively address the
8 growing need while minimizing the risk of a large buildout. These include: investing in
9 demand side resources, using surplus interconnection capacity to bring on new energy
10 resources on a faster timeline than the Proposed Generators;⁷⁴ using generator
11 replacement rights on either site to deploy solar plus storage instead; staggering
12 retirements in a way that would allow a more gradual buildout and reduce risk by giving
13 ELL time to see whether and how this load actually materializes; or even converting
14 Nelson 6 to burn gas, an option ELL appears to have been evaluating since at least
15 2019,⁷⁵ but still “has not completed an economic evaluation comparing that cost to other
16 alternatives.”⁷⁶

17 **Q. Has ELL’s assumed retirement timeline for Little Gypsy 2 and 3 remained**
18 **consistent over time?**

19 A. No. Comparing ELL’s own planning documents shows these dates have moved
20 substantially, without explanation. The 2023 IRP assumed Little Gypsy 2 & 3 would
21 deactivate in 2027;⁷⁷ notably, in ELL’s 2023 Preferred Portfolio, those retirements did
22 not trigger a need for new gas-fired capacity, but rather resulted in the addition of solar
23 and demand-side management resources.⁷⁸ At the time of the BP24 development, Little

⁷⁴ When asked in discovery, ELL responded that neither site relevant in this docket has surplus capacity (ELL response to Sierra 1-15). I discuss the possibility of interconnecting additional resources at these two sites specifically in Section VII.

⁷⁵ ELL response to Sierra 1-14.

⁷⁶ ELL response to EDF 1-16.

⁷⁷ 2023 ELL IRP at 27, Table 3.

⁷⁸ 2023 ELL IRP at 182.

Gypsy 2 & 3 were assumed to operate until the end of May, 2028.⁷⁹ In BP26, deactivation dates for Little Gypsy 2 & 3 moved again to a later date (end of May 2030). Given this pattern, and ELL's continued lack of commitment to any of these dates, they could continue to slip.

Q. Has ELL been consistent about the future of Nelson 6?

A. No. ELL's treatment of Nelson 6 site has also shifted repeatedly, even within this proceeding. Its own workpapers do not agree on when Nelson 6 will retire: the 2023 IRP showed a 2028 deactivation date without new gas-fired capacity as replacement, but rather resulting in the addition of solar and demand-side management resources.^{80,81} The modeling behind the 2024 CCCT RFP shows [REDACTED], while the BP26 Final Load & Capability workpapers show [REDACTED]

[REDACTED]

Underlying all of this is a more basic gap: ELL has not decided whether it will retire Nelson 6 or convert it to gas. [REDACTED]

[REDACTED]⁸⁴ There is, thus, no current cost estimate and no decision; yet BP26's resource balance already assumes the conversion,⁸⁵ and ELL

⁷⁹ ELL response to EDF 1-16.

⁸⁰ 2023 ELL IRP at 27, Table 3.

⁸¹ 2023 ELL IRP at 182.

⁸² ELL response to Sierra 2-6 (HSPM) (the "e. Generation" tab of the Sierra 1-9 workpaper reflects a 2031 Nelson 6 retirement, while the "Summer SAC L&C-wCCCT" tab of "Exhibit MJP-1 BP26 Final L&Cs w Chart_HSPM" (Sierra 1-1) reflects 2028; ELL explains the BP26 date is "more current").

⁸³ ELL response to Sierra 2-11 (HSPM).

⁸⁴ ELL response to Staff 1-90.

⁸⁵ ELL response to Staff 1-94; ELL response to EDF 1-16.

1 asserts the Nelson site is the most reasonable location for Westlake while noting it has no
2 analysis showing otherwise.⁸⁶

3 ELL does not state consistently, within its Application, whether and when Nelson 6 is
4 planned to deactivate, whether it will still be operating when Westlake comes online, or
5 whether it will instead convert to gas. The unit's assumed retirement is part of the
6 capacity reduction ELL relies on to establish its claimed need, and its status directly
7 affects the cost and interconnection basis of the Westlake project. ELL's advancing this
8 Application while these questions remain unresolved reinforces my broader concern that
9 its resource addition decisions were reached before the analysis meant to support them.

10 **V. ELL's CCCT-Oriented Procurement Process Means Real Alternatives Were**
11 **Never Examined, Missing Out on Potential Savings for Ratepayers.**

12 **Q. Setting aside your concerns about ELL's need analysis, has ELL justified its**
13 **selection of CCCTs as the resource to meet that need?**

14 A. No. ELL's procurement process was oriented toward a gas-fired resource from the outset,
15 and no real alternative to WF6 and Westlake was ever tested against them. Whether or
16 not ELL was technically required to run that comparison, the result is the same: better
17 alternatives were never considered. If certified, the CCCTs will expose ratepayers to
18 higher costs and risks than necessary.

19 Much like the load analysis, ELL's economic evaluation seems more like an effort to
20 justify a decision already taken, rather than a genuine starting point to find the right
21 resource. The way it is set up methodologically cannot lead to any meaningful results
22 from the outset. Even so, its results do not even support the Application: they show a thin
23 and very fragile margin, costs that outweigh benefits for the first decade of operations,
24 and a lock-in effect on costs, while benefits carry no such certainty.

⁸⁶ ELL response to Staff 1-90(k).

1 **A. ELL's planning and procurement process was oriented toward a major gas-fired**
2 **resource, leaving alternatives untested.**

3 **Q. How were WF6 and Westlake selected as the resources to meet ELL's claimed need?**

4 A. WF6 and Westlake were selected through the 2024 CCCT RFP. ELL's Economic
5 Evaluation Team evaluated the [REDACTED] it received using a "Total Supply Cost
6 Savings" metric. WF6 and Westlake both showed [REDACTED], while [REDACTED]
7 [REDACTED], a tolling agreement [REDACTED].⁸⁷ ELL selected all
8 [REDACTED] anyway, due to the claimed resource need and ELL's analysis showing [REDACTED]
9 [REDACTED].⁸⁸ The tolling agreement
10 ultimately did not move forward because ELL and the third party could not agree on
11 commercial terms; those negotiations were terminated in November 2025, leaving WF6
12 and Westlake as the two resources in this Application.⁸⁹

13 **Q. How was the resource need that informed the 2024 CCCT RFP identified?**

14 A. ELL's Final 2023 IRP concluded that over the long-term planning horizon, ELL would
15 need additional capacity to replace deactivated capacity and address load growth.⁹⁰
16 Consequently, in LPSC Docket No. X-37450, ELL provided notice of its intent to
17 conduct an RFP. However, the RFP was issued with a very narrow scope. Specifically, it
18 sought up to 2,000 MW of new build CCCT generation in the LRZ 9 region, with
19 individual resource capacity required to be in the range of 600 MW to 800 MW (summer
20 conditions) and with an in-service date no later than January 1, 2031. The RFP allowed
21 for bidders to submit proposals for Purchase Power Agreements ("PPAs"), tolling
22 Agreements, and/or Build-Own-Transfer agreements, and provided that certain self-build
23 options would be market-tested: one at or near ELL's existing Waterford site near
24 Killona, Louisiana, and one at or near ELL's existing Roy S. Nelson site in Westlake,
25 Louisiana.

⁸⁷ Plaisance Direct Testimony, at 13:10-12.

⁸⁸ Plaisance Direct Testimony, at 13:13-17.

⁸⁹ Plaisance Direct Testimony, at 13:18-21.

⁹⁰ Plaisance Direct Testimony, at 26:1-5.

1 **Q. Despite the narrow scope of the RFP, ELL witness Sullivan testifies that ELL “cast**
2 **a wide net” and performed “a diligent search for available options.”⁹¹ Has ELL**
3 **evaluated other resources as alternatives to WF6 and Westlake?**

4 A. No. ELL is pursuing other resources through separate procurement processes: a demand
5 response RFP, a solar RFP, and a battery storage RFP, but it has not evaluated any of
6 them against WF6 or Westlake.⁹² The contemporaneous RFPs do not test resources
7 against each other. First, the fragmentation of these procurements into separate, resource-
8 specific solicitations means no single evaluation ever compares these resource types
9 against each other on a level basis. Second, the sequence in which ELL is requesting
10 Commission approval for each of them may result in certain resources being locked in
11 before others, potentially crowding out options that would have better matched to how
12 load materializes in reality. ELL decides how much capacity to procure from each
13 technology, then selects among the options submitted within that predetermined
14 allocation, but this process does not necessarily result in the truly lowest reasonable cost
15 combination of resources.

16 **Q. ELL witness Sullivan further points out that the 2024 CCCT RFP was initiated**
17 **before the Commission's October 2024 amendments to the MBM Order took effect,**
18 **and that therefore those amendments do not technically apply in this case.⁹³ Does**
19 **that resolve your concern?**

20 A. No. Even assuming, without taking a position on that legal question, that the October
21 2024 amendments do not technically apply here, the underlying concern that a narrowly
22 scoped RFP does not test the full range of available alternatives, and can therefore lead to
23 suboptimal portfolios and increased costs for ratepayers, remains. This appears to be a
24 concern the Commission itself has already recognized through the MBM Order and
25 subsequent amendments, the latest of which requires that RFPs be “constructed as

⁹¹ Sullivan Direct Testimony, at 30:8-11.

⁹² See ELL's Response to SIERRA 1-11 (objecting to the characterization that the contemporaneous RFPs sought resources “considered as potential resource alternatives to the proposed Westlake and WF6 power stations” and identifying the three RFP notices but without specifying any bid results or comparative analysis against the Proposed Generators in this docket).

⁹³ Sullivan Direct Testimony, at 29:18-30:2.

1 broadly as possible to allow for review of all available options to add generating
2 capacity.”⁹⁴ Thus, regardless of whether that amendment technically applies to this
3 particular RFP, to my understanding, nothing prohibited ELL from a broader, resource-
4 type-neutral solicitation, only that ELL chose not to.

5 **Q. Are there factors that could create an incentive for ELL to favor CCCT resources in**
6 **this case and within its broader resource buildout, as discussed in Section III?**

7 A. Yes. ELL, together with other Entergy operating companies, entered into a Gas Turbine
8 and Power Train Exclusivity Agreement with Mitsubishi Power Americas, [REDACTED]

9 [REDACTED]
10 [REDACTED]
11 [REDACTED]
12 [REDACTED]
13 [REDACTED]
14 [REDACTED]
15 [REDACTED]
16 [REDACTED]
17 [REDACTED]
18 [REDACTED]⁹⁷

19 **Q. In his direct testimony, ELL witness Nguyen concludes that “WF6 and Westlake**
20 **were the lowest reasonable cost viable resource alternatives available to meet ELL**
21 **customers’ need for long-term efficient and reliable capacity in accordance with the**
22 **LPSC’s MBM Order.”⁹⁸ Do you agree?**

⁹⁴ See Attachment A to General Order 10-14-2024 (R-34247), LPSC Docket No. R-34247, *In re: Rulemaking to consider changes to Commission General Order dated October 29, 2008 (Docket No. R-26172 Subdocket C) (“Market Based Mechanisms Order”)* to incorporate formal complaint procedures, at ¶ 3.

⁹⁵ ELL response to Staff 1-48, Attachment Staff 1-48 MPWA_Entergy_Exclusivity_Agreement_Executed_HSPM.

⁹⁶ Id.

⁹⁷ Id.

⁹⁸ Nguyen Direct Testimony, at 3:22-4:1.

A. No. Witness Nguyen's conclusion reflects only a comparison between the [REDACTED] proposals submitted to a CCCT-only RFP, not a test against the broader set of resources that could meet the same need. As discussed above, ELL never conducted an evaluation of non-gas alternatives against WF6 and Westlake, and its fragmented, resource-by-resource procurement never compares resource types on a level basis; the record never establishes these units as the lowest reasonable cost option. Additionally, as I explain in Section V.B, even the economic case ELL does present is too sensitive to support that conclusion.

Q. What are the potential impacts of certifying WF6 and Westlake without a real alternatives analysis?

A. No alternatives analysis has been conducted. Regardless of whether an all source approach and cost comparison were required at the time the RFP was issued, the outcome is the same: a resource portfolio that carries higher costs and risks than other available options, even taking ELL's claimed load need at face value. Certifying WF6 and Westlake now could crowd out other resources (including resources from the concurrent DR, battery, and solar procurements) that could produce higher net benefits for ratepayers if actually compared against these units. Given the questions raised in Section IV in this testimony about the claimed need, the flaws in ELL's economic analysis (see Section V.B), and the other near-term options ELL currently has (see Section VII), ELL has the time and should run an all-source RFP and choose among real alternatives that will help meet the need at the lowest reasonable cost.

B. ELL's economic analysis does not provide a reliable basis for certifying the Proposed Generators.

Q. What are your specific concerns with ELL's economic analysis?

A. Based on my review of ELL's economic evaluation, I have four principal concerns, which I address in turn:

- First, the Net Benefit analysis is methodologically flawed: it is constructed in a way that cannot produce a reliable result, because the projected benefits rest on

which counterfactual was selected, and that counterfactual was itself an ELL-selected assumption.

- Second, even accepting ELL's own methodology, the projected Net Benefit is a [REDACTED], and is therefore highly uncertain.

- Third, the costs and benefits are asymmetric in timing: the costs are locked in and incurred immediately, while the benefits are back-loaded and uncertain, such that [REDACTED].

- Fourth, ELL did not sufficiently test the sensitivity of its results to the key uncertainties that drive them, limiting its sensitivity analysis to property tax abatement scenarios rather than the gas price, load, and policy assumptions that matter most.

Q. You mentioned that ELL did not evaluate the CCCTs against other resource types. What analysis does ELL provide to support the claim that WF6 and Westlake are in the public interest?

A. ELL Witness Nguyen presents the economic evaluation of the proposals in the 2024 CCCT RFP. According to the witness, the economic evaluation “estimated the full-in economic cost and benefit to customers of each proposal evaluated, while taking into account other relevant factors such as risk mitigation and reliability.”⁹⁹ This resulted in a Customer Net Benefit, measured by subtracting all costs from all benefits attributable to the proposed unit over its useful life, on a present value basis.¹⁰⁰

Q. Please summarize the results of ELL’s economic assessment.

⁹⁹ Nguyen Direct Testimony, at 6:14-16.

¹⁰⁰ Nguyen Direct Testimony, at 6:16-21.

A. ELL found both CCCTs to result in net benefits under both the original project cost estimates, as well as in an updated analysis reflecting the cost increases. The results of the updated analysis are presented in Table 2.

Table 2: Customer Net Benefits (\$MM NPV, 2030 – 2060)¹⁰¹

Proposal ID	NPV (2025\$ \$MM)	NPV \$/kW-Yr. Levelized Real (2025\$)	NPV \$/MWh Levelized Real (2025\$)
Westlake			
Waterford 6			

Q. Do you find the economic analysis and resulting net benefits convincing?

A. No. Even setting aside the concerns outlined in Sections IV and V.A regarding need and resource selection respectively, and accepting ELL's own need framing and reasoning for the selection of CCCT technology as given, the economic case ELL presents for the Westlake and WF6 units is smaller and more fragile than the Application suggests. ELL's estimation of the Net Benefit is methodologically flawed, and the projected Net Benefit is small and highly sensitive to key assumptions, such that even modest deviations from ELL's current assumptions quickly convert the projected Net Benefit into a net cost for ratepayers.

1. The net benefit analysis is methodologically flawed

Q. Can you provide additional information on how the Net Benefit was calculated?

A. Yes. The Net Benefit calculation is based on the sum of the projected benefits minus the projected costs over the lifetime of each proposed unit. The projected benefits consist of capacity benefits and energy benefits. The costs include the revenue requirement of the associated infrastructure (acquisition, transmission, additional capital), the generator non-fuel operations and maintenance (“O&M”) costs, variable O&M costs, and fixed fuel demand charge.

¹⁰¹ ELL response to Sierra 1-1.

1 **Q. Please explain how the energy benefits are estimated and describe the “base” and**
2 **“change” cases.**

3 A. The energy savings are estimated as the difference in the Variable Supply Cost (“VSC”)
4 of two portfolios: the “base” case and the “change” case. Specifically, for each proposal
5 received in the 2024 CCCT RFP, ELL ran a “change” case in the AURORA production
6 cost model that added that specific proposal to ELL's existing generation portfolio using
7 BP25 assumptions for the period 2030-2044. ELL then calculated the energy benefit by
8 comparing that “change” case against a “base” case.

9 **Q. Please describe the “base” and “change” cases.**

10 A. According to ELL witness Nguyen, the “base” case consists of a portfolio in which the
11 proposed unit is replaced with two CCCTs.¹⁰² The IM report includes a different
12 explanation of [REDACTED] in the base case: [REDACTED]

13 [REDACTED]
14 [REDACTED]
15 [REDACTED]¹⁰³ The underlying workpapers outline assumptions that
16 describe a different base case. Specifically, one of the assumptions for the VSC
17 calculation is “Replace 2030 CCCT with [REDACTED]” at both the Waterford and Westlake
18 locations.¹⁰⁴

19 In short, there is some discrepancy as to whether [REDACTED], two generic
20 CCCTs, or [REDACTED] are being used as a counterfactual to the Proposed Generators.

21 **Q. Do you have concerns around ELL’s methodology in estimating the energy benefits**
22 **of the Proposed Generators?**

23 A. Yes. This inconsistency in the counterfactual points to the exact methodological issue I
24 identify: a comparison of one unit’s performance against that of another without

¹⁰² Nguyen Direct Testimony, at 12:2.

¹⁰³ Exhibit PDN-2, at 33-34.

¹⁰⁴ ELL response to Sierra 1-1, Add 2_

ELL_CCCT_RFP_Evaluation_SelfBuildUpdate_Waterford_Westlake_Ref_Sendout 260206_HSPM, tab “VSC Summary”.

1 explanation as to why that is a reasonable counterfactual is not meaningful or
2 informative. Any such comparison could be constructed to result in net benefits.

3 First, whether the base case includes [REDACTED] and
4 provide no real insight for the broader question of whether they are the lowest reasonable
5 cost resources or whether they are needed in general. Second, WF6 or Westlake
6 outperforming a generic CCCT with the projected margin (ELL estimates that Westlake
7 results in VSC savings of [REDACTED] MM in NPV) is not reasonable; ELL has not shown or
8 argued that the CCCTs would operate at lower cost than a generic CCCT. To my
9 knowledge, ELL is not proposing a different configuration or technologically advanced
10 CCCT (compared to a generic one). If on the other hand, the actual substitution is [REDACTED]
11 [REDACTED] rather than CCCTs, the comparison changes again: [REDACTED]
12 [REDACTED]
13 [REDACTED]
14 [REDACTED] since the proposal is being compared to a resource
15 that is not designed or suited for baseload dispatch.¹⁰⁵

16 In short, methodologically, the energy benefit calculation is not well designed and offers
17 no meaningful insight or reliable estimate.

18 **Q. Please explain how the capacity benefits are calculated.**

19 A. [REDACTED]
20 [REDACTED]
21 [REDACTED]¹⁰⁶ ELL's reasoning behind this assumption is that new-build is the standard
22 assumption for the lowest-cost known option for adding long-term generation capacity.¹⁰⁷
23 This benefit is simply the capacity the resource can provide and that ELL assumes will be
24 needed, multiplied by the cost that would otherwise be incurred to build that capacity.

¹⁰⁵ Sierra 1-1 Add 2 2024 ELL CCCT RFP Economic Evaluation Model - Updated Analysis 260206_HSPM; ELL response to Sierra 1-1, Add_2_ ELL_CCCT_RFP_Evaluation_SelfBuildUpdate_Waterford_Westlake_Ref_Sendout 260206_HSPM, tab "VSC Summary".

¹⁰⁶ PDN-2 at 36.

¹⁰⁷ ELL response to Sierra 2-2a.

Q. What are your concerns regarding the estimation of the capacity benefits?

A. My main concern is that neither of the two factors, the capacity need in ELL's system and the cost that would be otherwise incurred to build it, is established in ELL's analysis. They are simply assumptions made by ELL that lack analytical basis.

First, ELL assumes a capacity need exists throughout the useful life of the Proposed Generators, in every season. If that need does not exist, or does not exist to the extent ELL claims throughout the 30 year horizon, there will be no marginal capacity being avoided, and the capacity benefit will be significantly reduced or eliminated. It is worth noting that the capacity benefit calculation is not a load and resource analysis, and thus offers no insight or conclusion as to whether there would actually be a need, it simply assumes it. Given my concerns about the persistence of the load, as outlined in Section IV.B, I am concerned that this benefit might not materialize as currently projected. Furthermore, even if the need exists at the MISO level, if the unit's accredited capacity falls below what ELL is currently projecting either because of a change in MISO resource accreditation rules or because of the unit's (under)performance, the benefit could be significantly reduced.

Second, this benefit depends on a ■ remaining the lowest-cost resource for adding capacity throughout the evaluation period. ELL itself describes the ■ benchmark as "the lowest-cost known option" only as of the time of this analysis. As technology costs change, including for long duration energy storage and other capacity resources, the lowest-cost capacity resource can change as well. If a lower-cost capacity resource becomes available at any point over the life of the Proposed Generators, the avoided-cost benchmark ELL used to justify this benefit would no longer hold, and the capacity benefit calculated here would be overstated relative to what a benchmark at that time would show. Even if a ■ were to remain the relevant capacity benchmark throughout, ELL's analysis assumes essentially no technological progress for the ■ itself, only rising costs over time.

ELL has not tested how this benefit changes if either of these two assumptions, that a need exists and that a [REDACTED] remains the least-cost capacity resource, does not hold over time.

2. The claimed net benefits over the CCCTs' useful life are highly uncertain and small relative to the scale of the investment.

Q. How do the different cost components compare to the projected benefits?

A. Table 3 and Figure 6 below show the NPV of each cost and benefit component in ELL's reported net benefit for Westlake and WF6.

Table 3: Projected Benefits and Costs of Westlake and WF6 in ELL's Economic Evaluation (NPV 2025\$MM)¹⁰⁸

	Westlake	WF6
Benefits		
Variable Supply Cost Savings	[REDACTED]	[REDACTED]
Capacity Benefit	[REDACTED]	[REDACTED]
	[REDACTED]	[REDACTED]
Costs		
Acquisition Revenue Requirement	[REDACTED]	[REDACTED]
Transmission Revenue Requirement	[REDACTED]	[REDACTED]
Additional Capital Revenue Requirement	[REDACTED]	[REDACTED]
Generator Non-fuel O&M	[REDACTED]	[REDACTED]
Generator Variable O&M	[REDACTED]	[REDACTED]
Generator Fixed Fuel Demand Charge	[REDACTED]	[REDACTED]
	[REDACTED]	[REDACTED]

On the benefit side, the capacity benefit accounts for the substantial majority of total projected benefits for both units, with the energy benefit (VSC Savings) contributing a smaller share. On the cost side, the largest component is the revenue requirement, with additional components being the generator non-fuel O&M costs, the variable O&M costs, and the fixed fuel demand charges.

¹⁰⁸ Sierra 1-1 Add 2 2024 ELL CCCT RFP Economic Evaluation Model - Updated Analysis 260206_HSPM.

1
2

[REDACTED]

[REDACTED]

3
4

5 **Q. What are your main observations from Figure 6?**

6 **A.** Three observations stand out:

7 • [REDACTED]
8 [REDACTED]
9 [REDACTED]
10 [REDACTED]

11 • [REDACTED]
12 [REDACTED]
13 [REDACTED]
14 [REDACTED]
15 [REDACTED].¹⁰⁹

¹⁰⁹ Even if we include the fixed fuel component in the calculation of the capital cost of the CCCT (a fixed fuel charge is included in the avoided cost of the CT, see Sierra 4-2 ELL BP26 Avoided Capacity Cost Curves - 250519_HSPM) as well as the transmission component, the resulting capital cost of the CCCT is lower than the capacity benefit.

1 • [REDACTED]
2 [REDACTED]
3 [REDACTED]

4 **Q. Please elaborate on your observation that the margin is thin.**

5 A. ELL estimates that the Proposed Generators will deliver a Net Customer Benefit of
6 roughly [REDACTED] over the projects' life.¹¹⁰ Specifically, ELL is asking the
7 Commission to approve \$4.1 billion in capital investment, supported by cost estimates
8 that are subject to significant uncertainty and that the Independent Engineer found meet
9 only Class 4/5 standards, with an accuracy range of -30%/+50% for Class 4 and -
10 50%/+100% for Class 5.^{111,112} Against an investment of this scale and this degree of
11 uncertainty, a projected lifecycle benefit of this size is a [REDACTED] that does not inspire
12 confidence in the results. The claimed WF6 benefit equals only about [REDACTED] of that project's
13 own cost, a margin small enough that an [REDACTED] cost increase, well within the accuracy range
14 of ELL's own estimate, would erase it entirely and leave ratepayers with net costs. The
15 claimed Westlake benefit, at just under [REDACTED] raises the same concern.¹¹³

16 **Q. Please elaborate on your observation that the capacity benefit exceeds the revenue**
17 **requirement.**

18 A. As shown in Table 3, the NPV of the capacity benefit alone, i.e. the avoided capacity cost
19 of the [REDACTED] million for Westlake, [REDACTED] million for WF6) exceeds the NPV of the
20 total revenue requirement for each project (even when accounting for the additional
21 capital and the fixed fuel demand charge). This implies that the Proposed Generators are
22 cheaper to build than the [REDACTED] ELL uses as its capacity benchmark. In effect, the analysis
23 reduces to a capital-cost comparison between a CCCT and a [REDACTED], with the

¹¹⁰ Sullivan Direct Testimony at 36:15–18.

¹¹¹ Exhibit PDN-2 at 64 (Worley Cost Estimate Classification Matrix; finding the self-build estimates "are more appropriately classified as Class 4 or 5"); see also id. at 39.

¹¹² Estimate classification is further explained in Section VI.B of my testimony.

¹¹³ Calculated as each unit's updated customer net benefit divided by its updated project cost. Net benefits: Nguyen Direct Testimony at 18:8 [REDACTED]. Costs: Pressler Direct at 43:1 (Westlake, \$2,091.0 million, Pressler Direct at 37:3 (WF6, \$2,027.2 million).

1 [REDACTED] assumed to be the more expensive resource. That result runs contrary to what has
2 generally been observed in resource costs to date, where [REDACTED]
3 [REDACTED] to build than CC units of
4 comparable capacity. If the [REDACTED] is not actually more expensive than the
5 Proposed Generators on a capital-cost basis, the capacity benefit, and with it, ELL's
6 claimed net benefit, would be substantially overstated.

7 **3. According to ELL's Economic Evaluation, the CCCTs result in net costs (NPV,**
8 **\$2025) up to 2050.**

9 **Q. Please elaborate on your observation that costs and benefits are different in the way**
10 **they can change once the units are constructed.**

11 A. Costs are locked in: the fixed revenue requirement, fixed O&M, and fixed fuel charge are
12 not expected to change once the units are built, and if they did, they would be more likely
13 to increase. Benefits, on the other hand, are not locked in. The capacity benefit could
14 shrink or disappear if capacity needs change. This is a particular concern in a system that
15 already carries significant risk of being overbuilt. The energy benefit could also come in
16 much lower than projected if load does not materialize as forecast. As I explain in Section
17 IV, that forecast is inflated. In short, in ELL's own economic evaluation, costs are certain
18 and show up immediately; benefits are uncertain and are expected to materialize at a
19 much slower pace. My concern is that the projected benefits are more likely than not to
20 materialize at an even slower rate than already projected, or not materialize at all, leaving
21 ratepayers to simply cover the bill, while ELL recovers the costs and earns a return.

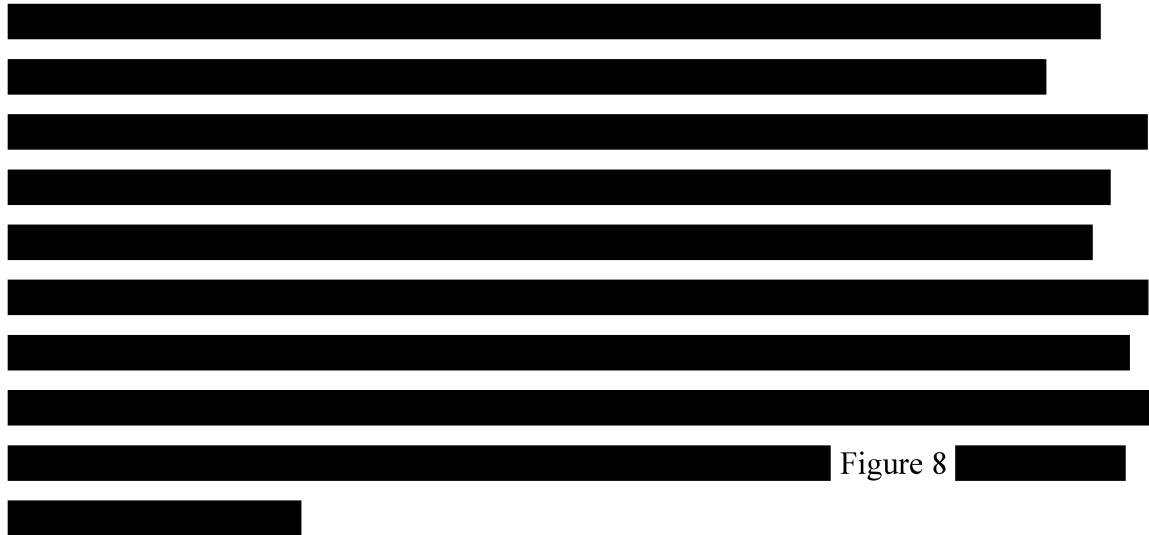
22 **Q. You stated that costs are immediate, while benefits are projected to materialize (if**
23 **they do) at a much slower pace. Please explain.**

24 A. The cost side will be realized by customers right away. ELL's own numbers show a first-
25 year revenue requirement of \$244.7 million for WF6 and \$253.1 million for Westlake,
26 before any of the claimed savings show up.¹¹⁴ The benefits, by contrast, are spread across
27 a thirty-year period and depend on load, capacity prices, and other assumptions matching

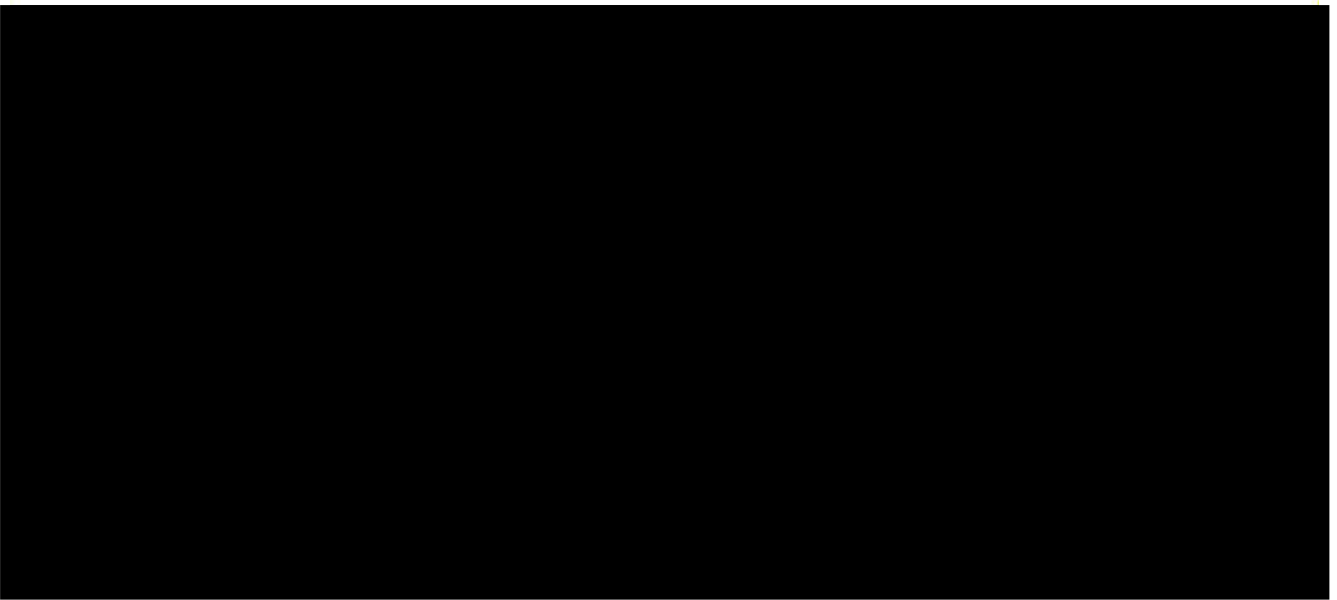
¹¹⁴ Sullivan Direct Testimony at 20:6-12

ELL's assumptions during that entire period. It is interesting to see that ELL's own analysis, without any change in the inputs or calculations, predicts significant [REDACTED] years of operations of those units.

Figure 7 presents the projected costs and benefits as calculated in ELL's analysis, with benefits shown above the axis and costs below for WF6. [REDACTED]



[REDACTED]



1

2

3

4 **4. The analysis did not sufficiently investigate the sensitivity of the results to key**
5 **uncertainties.**

6 **Q. Has ELL tested how sensitive these net benefit figures are to key uncertainties?**

7 A. ELL's sensitivity testing was limited in scope, and the testing that was performed is not
8 particularly meaningful. The two property tax abatement scenarios reflect only changes to
9 the capital cost structure and do not address the more significant uncertainties underlying
10 this analysis.

11 *Table 4: Sensitivity Scenarios Customer Net Benefits (\$MM NPV, 2030-2060)¹¹⁵*

Scenario	Westlake	WF6
Reference	■	■
80% Property Tax Abatement	■	■
93% Property Tax Abatement	■	■
Low Gas, No CO2	■	■

¹¹⁵ Nguyen Direct Testimony at 19:2

1 **Q. What are your observations regarding the low gas price, no CO2 sensitivity?**

2 **A.** [REDACTED]
3 [REDACTED]
4 [REDACTED]
5 [REDACTED]
6 [REDACTED]
7 [REDACTED]
8 [REDACTED]
9 [REDACTED]
10 [REDACTED]
11 [REDACTED]
12 [REDACTED]
13 [REDACTED]
14 [REDACTED]
15 [REDACTED]
16 [REDACTED]
17 [REDACTED]
18 [REDACTED]

19 **Q. Did ELL test a high, rather than low, gas price future?**

20 **A.** No. In discovery. ELL confirmed that "[t]he High Gas, High CO2 case was not run for
21 this RFP," notwithstanding that the model contained a placeholder for that scenario, and
22 further asserted, without presenting supporting modeling, that "even if the High Gas,
23 High CO2 case had been run, Westlake and Waterford 6 would have still been the most
24 economic resources in this RFP."¹¹⁶

25 Although I am concerned that ELL asserts a conclusion its analysis has not actually
26 produced, I also think that a high gas price sensitivity run using ELL's flawed
27 methodology would not be particularly insightful. A high gas price future would likely

¹¹⁶ ELL response to Sierra 3-7.

1 increase the Proposed Generators' measured benefits under this methodology, [REDACTED]
2 [REDACTED]
3 [REDACTED]. That is
4 an artifact of the assumed alternative, not evidence that committing to the Proposed
5 Generators is a prudent response to gas price risk. A high gas price scenario is the
6 condition under which fuel-free resources would deliver the greatest value, because they
7 displace expensive gas-fired energy without incurring fuel costs, but this alternative is
8 never considered in ELL's analysis.

9 **Q. Were you able to assess ratepayers' risk exposure to an increased gas price?**

10 A. Yes, although I followed a different approach. Specifically, I took ELL's Henry Hub gas
11 price assumptions and estimated the fuel cost of the two CCCTs under ELL's projected
12 capacity factors (as included in its updated economic evaluation).¹¹⁷ This likely
13 understates actual costs, since the delivered gas price to each unit would be higher than
14 the Henry Hub price, but it still shows the magnitude of the exposure. Figure 9 shows
15 ELL's projected prices at Henry Hub, alongside the Energy Information Administration's
16 ("EIA") Annual Energy Outlook ("AEO") Henry Hub forecast under both its baseline
17 and low gas price scenarios. Values are shown through [REDACTED], the final year for which
18 ELL provided its forecast. [REDACTED]
19 [REDACTED] For the EIA forecasts, I included the values up to 2050 as forecast,
20 and then escalated in the same way ELL does up to 2060.

21
22
23
24

¹¹⁷ ELL response to Sierra 1-24 (Henry Hub Price Forecast); ELL response to Sierra 1-1 Add 2 2024 ELL CCCT RFP Economic Evaluation Model - Updated Analysis 260206_HSPM, tab VSC Library (Projected Generation).

1
2

[REDACTED]

[REDACTED]

3

4

[REDACTED]

5

[REDACTED]

6

[REDACTED] Even a more

7

modest price deviation matters: applying the 6.28% gas price increase ELL itself reported

8

in Docket No. U-37425,¹¹⁸ the resulting cost increase would be \$274 million.

9

All of these costs could be avoided or significantly reduced under a portfolio that

10

included more fuel-free resources, such as renewable energy and EE measures. The

11

potential savings would be even larger when also accounting for firm transportation

12

costs, which for the two units total [REDACTED] million and could likewise be avoided under a

13

fuel-free portfolio.¹¹⁹

¹¹⁸ ELLs quarterly monitoring report in Docket No. U-37425 stated: “Since October 2024, when ELL sought certification of the 3 CCCTS, Entergy System Planning & Operations has raised its long-term outlook for natural gas prices, both at the Henry Hub and delivered to the Franklin Farms and Waterford 5 sites. Based on the Reference Case Natural Gas Forecast summarized in the table below, the forecasted average natural gas price for 2028-2045, the time that the 3 CCCTS are expected to be in commercial service, has risen by an average of 6.28% as measured by Henry Hub prices and 9.46% for Waterford 5 and 2.88% for Franklin Farms as measured by delivered—to-plant prices.”

Docket No. U-37425, Laidley Generation and Transmission Project Confidential Quarterly Monitoring Report for 2026, Pursuant to Order No. U-37425, May 15, 2026.

¹¹⁹ See Table 3, Projected Benefits and Costs

1 **Q. Did ELL test different load growth scenarios?**

2 A. No. ELL did not meaningfully test load growth as part of its sensitivity analysis.

3 [REDACTED]
4 [REDACTED]
5 [REDACTED]
6 [REDACTED]

7 **Q. What is your conclusion regarding ELL's economic sensitivity analysis?**

8 A. ELL's analysis is methodologically flawed. The base case used for comparison is
9 described inconsistently across ELL's own record and lacks any analytical basis, the
10 capacity benefit depends on unproven assumptions about both future capacity need and
11 the durability of a single benchmark resource, and key sensitivities were never run.
12 Even accepting ELL's methodology and assumptions as presented, the results themselves
13 show poor performance. The Proposed Generators [REDACTED]
14 [REDACTED], and the
15 size of that eventual benefit is highly sensitive to key uncertainties.
16 I find that ELL's economic analysis does not provide a reliable basis for certifying the
17 Proposed Generators. And even if the Commission were to rely on it, ELL's own results
18 do not support certification.

19 **VI. If the Proposed Generators Are Certified, Ratepayers Will Bear Unnecessary**
20 **Risks With No Way Out.**

21 **Q. Beyond the concerns you have outlined around ELL's need and economic analyses,**
22 **are there other issues you believe the Commission should consider?**

23 A. Yes. In addition to those concerns, I want to highlight the risks to which existing
24 ratepayers would be exposed to if the Proposed Generators are certified without
25 consideration of alternatives or certain conditions in place. Certifying the Proposed
26 Generators would commit ratepayers to more than the \$4.1 billion investment alone,
27 which reflects only the upfront capital cost; ratepayers would also bear decades of

ongoing costs on top of it, along with several distinct risks for the life of the units. First, ELL's cost estimates for the Proposed Generators could still change materially, and the Company is simultaneously executing several other large-scale, gas-fired construction projects that compete for the same contractors, equipment, and labor, increasing the likelihood of cost overruns and schedule delays. Second, ELL's growing reliance on gas-fired generation exposes ratepayers to fuel price volatility, fuel supply and transportation risk, and future policy risk, each of which ELL has little ability to control once these units are built. Third, gas-fired generation carries a correlated outage risk that becomes more consequential as a larger share of ELL's fleet depends on the same fuel source, particularly during the extreme weather conditions when reliable generation matters most. And while existing ratepayers will be exposed to all these increased risks and their financial consequences, ELL's proposed and existing cost recovery structure largely protects ELL, which could continue recovering its costs and earning a rate of return regardless of that outcome.

A. The Proposed Generators carry execution risks in the near-term.

Q. Please elaborate on the execution risk that you think ELL and consequently ratepayers are facing.

A. ELL is simultaneously advancing multiple large-scale, multi-year construction projects, including WF6, Westlake, the three CCCTs approved in Docket No. U-37425 (Franklin Farms 1, Franklin Farms 2, and Waterford 5), and the seven Evest CCCTs in Docket No. U-37882, along with the transmission facilities needed to support them. These projects will compete for contractors, equipment, and management attention, and a cost overrun or schedule delay in any one of them could cascade into the others.

Q. ELL has secured production queue spots for turbines through an Exclusivity Agreement with Mitsubishi. Does that address your concerns?

A. Not really. The execution concern is not limited to the delivery of the turbines. ELL's buildout is occurring at the same time as comparable buildouts within Entergy, across the Southeast, and throughout MISO, which could create shortages in other equipment and

labor, beyond turbines specifically. This cost increase has already begun to show up, as I discuss below in the context of escalating labor and subcontracted engineered equipment costs.

ELL's construction schedule illustrates the scale of this exposure: from December 2028 to June 2031, ELL is projecting the completion of 12 new CCCT units, adding approximately 9 GW of new CC capacity, more than the entirety of its currently owned CC fleet.¹²⁰

- Franklin Farms 1 & 2: December 2028
- Waterford 5: December 2029
- WF6: July 2030
- Westlake: October 2030
- Richland Parish 1 & 2: March 2030
- Richland Parish 3 & 4: October 2030
- Pointe Coupee 1 & 2: December 2030
- Pointe Coupee 3: June 2031

ELL is not the only utility pursuing large-scale gas-fired buildout on this timeline. Within Entergy, sibling operating companies covered by the same Mitsubishi turbine exclusivity agreement are pursuing comparable projects, with Entergy Mississippi, Entergy Arkansas, and Entergy Texas together committed to ■ turbines.¹²¹ Within Louisiana, Cleco has announced a 756 MW gas plant in Rapides Parish tied to a data center development.¹²² More broadly across the Southeast, Georgia Power Company is planning 3.7 new CC capacity,¹²³ and Duke Energy Progress and Carolinas are planning 6.8 GW of new CC capacity and 2.8 GW of CT capacity by 2033.¹²⁴ And within MISO more broadly, members in Indiana, Missouri, Wisconsin, and elsewhere are pursuing new gas-

¹²⁰ ELL response to Staff 1-89(h).

LPSC Docket No. U-37882: Direct Testimony of Norman Grunden, Table 2: Key Project Milestones, at 30.

¹²¹ ELL response to Staff 1-48, Attachment Staff 1-48 MPWA_Entergy_Exclusivity_Agreement_Executed_HSPM.

¹²² LPSC Docket No. 38035, Direct Testimony of Robert Breedlove, at 14:18.

¹²³ Georgia Power, Georgia Power Requests Certification of Approximately 9,900 MW of New Resources from the Georgia Public Service Commission, Press Release (July 31, 2025), <https://www.georgiapower.com/news-hub/press-releases/georgia-power-requests-certification-of-approximately-9900-mw-of-new-resources-from-the-georgia-psc.html>.

¹²⁴ Duke Energy, 2025 Carolinas Resource Plan, Executive Summary, Figure 7, available at: <https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/2025/00-executive-summary-2025-nc-final-nodocket.pdf?rev=b6f72e856654454d9994346b39471808>

1 fired capacity on similar timelines. To the extent equipment manufacturing capacity,
2 contractor availability, and skilled labor are constrained industry-wide, ELL's projects are
3 competing for the same resources as all of these other projects; many of which also
4 require significant investment in fuel supply infrastructure and transmission construction,
5 further tightening the market for some of the same inputs.

6 **Q. Beyond increased costs, are there other possible consequences of this condensed**
7 **timeline and concentrated gas-fired buildout?**

8 A. Yes. Execution risk is not just a cost issue; it is also a delivery and reliability issue, since
9 a delay in bringing these units online could leave ELL needing to procure replacement
10 capacity or energy from the market at potentially higher cost. This is one reason a more
11 diversified portfolio, including energy efficiency, demand response, and customer-sited
12 resources, as I discuss in Section VII, is preferable to concentrating nearly all of ELL's
13 near-term capacity additions in large gas-fired units: a single point of execution failure,
14 whether in equipment delivery, labor availability, or project management, threatens the
15 reliability benefit ELL says these units are meant to provide. Shorter-lead-time resources,
16 by contrast, could begin providing energy and capacity sooner, hedging against those
17 risks, while delivering cost savings in the interim.

18 When asked in discovery what steps it is taking to address this risk, ELL pointed only to
19 seeking an expedited Commission decision — not to any step that would actually
20 mitigate the underlying execution or delivery risk itself, such as diversifying its near-term
21 resource additions.¹²⁵

22 **Q. Aside from the construction of the generators, do you have other concerns about**
23 **ELL's plan to reliably deliver the capacity and energy from the Proposed**
24 **Generators?**

25 A. Yes. To reliably provide energy and capacity, the units need secure fuel supply. As of
26 ELL's testimony, it had not negotiated the contracts needed to supply or transport natural

¹²⁵ ELL response to EDF 1-14.

1 gas to the Proposed Generators, and it has not disclosed in this proceeding what
2 arrangements it is pursuing or at what cost. For Westlake specifically, [REDACTED]

3 [REDACTED]
4 [REDACTED].¹²⁶

5 This might present an execution concern in its own right. [REDACTED]
6 [REDACTED]
7 [REDACTED]
8 [REDACTED]
9 [REDACTED]

10 **B. The \$4.1 Billion price tag is most likely an underestimate of what ratepayers will**
11 **eventually pay for the construction of the Proposed Generators.**

12 **Q. Are ELL's cost estimates for the self-build proposals reliable?**

13 A. No. The record itself raises concerns about ELL's ability to estimate and manage these
14 costs. The Independent Engineer, Worley Consulting, found that the cost estimates for
15 both the Waterford 6 and Westlake self-build proposals only narrowly met the minimum
16 qualifications for a Class 4 cost estimate, not the Class 3 estimate the self-build proposals
17 claimed.¹²⁷ ELL's own self-build team acknowledged that the estimates were based on as-
18 built reference projects Entergy had recently constructed, rather than a project-specific
19 estimate meeting Class 3 standards. Thus, the estimates are more appropriately classified
20 as Class 4/5 estimates.¹²⁸

21 **Q. What do the different classes mean?**

22 A. According to Worley's Cost Estimate Classification Matrix, used to determine the
23 appropriate classification for the cost estimates of the Proposed Generators, the accuracy
24 ranges for different classes differ significantly: a Class 4 estimate carries an expected
25 accuracy of -30% to +50% and a Class 5 estimate -50% to +100%. In assigning a "typical

¹²⁶ ELL response to Staff 3-21, Clarifying Questions for Self Build Proposals_HSPM.

¹²⁷ Exhibit PDN-2, at 61 of 85.

¹²⁸ Exhibit PDN-2, at 42 of 85.

1 purpose of estimate” to each class, Worley notes that Class 5 and 4 estimates are used for
2 “Concept screening” and “Study or feasibility”, which “budget authorization or control”
3 typically utilizes a Class 3 estimate.¹²⁹

4 **Q. Have the cost estimates for the Proposed Generators already increased since they**
5 **were first developed?**

6 A. Yes. Both units' current cost estimates are higher than the price submitted just over a year
7 earlier in the 2024 CCCT RFP. WF6's current estimate is \$2,027.2 million,¹³⁰ up from its
8 RFP bid of \$[REDACTED],¹³¹ an increase of approximately [REDACTED]. Westlake's current
9 estimate is \$2,091.0 million,¹³² up from its RFP bid of \$[REDACTED]¹³³ an increase of
10 approximately [REDACTED]. According to ELL Witness Pressler and broken down in
11 response to Staff 1-31, WF6's increase reflects growth in the engineering, procurement
12 and construction (“EPC”) contract, financing costs, and transmission interconnection
13 costs as design work matured since the bid stage, while Westlake's increase reflects both
14 a change in EPC estimating basis and the addition of transmission upgrade costs that
15 were not contemplated in the original bid, tied in part to unresolved questions about the
16 future of the existing generating unit at the site.¹³⁴ Thus, cost escalation has already
17 occurred, reinforcing the point made above about the Company's continued exposure to
18 further cost escalation as these estimates continue to be refined.

19 **Q. Has ELL considered its broader proposed buildout when developing the cost**
20 **estimates?**

21 A. Based on my review, I do not have reason to believe it has. If ELL could not produce a
22 rigorous analysis evaluating the costs and specific construction issues for the Proposed
23 Generators, but instead provided estimates that are simply “back-calculated from an 'as-

¹²⁹ Exhibit PDN-2, at 64 of 85.

¹³⁰ Pressler Direct Testimony, Table 1 (HSPM), at 37.

¹³¹ ELL response to Staff 1-30a.

¹³² Pressler Direct Testimony, Table 3 (HSPM), at 43.

¹³³ ELL response to Staff 1-30a.

¹³⁴ ELL response to Staff 1-31.

built' cost reference and modified for capacity,”¹³⁵ there is no basis to assume it has accounted for how execution and cost risk are compounded by the parallel construction of ELL's other projects. It is worth noting that ELL is simultaneously seeking certification of seven CCCTs in Docket No. U-37882, five of which are similarly priced on Class 4 estimates, while the associated ELL-funded transmission is priced on a Class 5 estimate, indicating similar lack of accuracy in cost estimates across its buildout.¹³⁶

Q. Are there recent examples of ELL's actual project costs exceeding its estimates?

A. Yes. A recent quarterly monitoring report in LPSC Docket No. U-37425 shows that capital costs for the Laidley generation and transmission projects came in approximately \$465 million, or 12 percent, above the prior reported estimate.¹³⁷ Specifically, the cost for Waterford 5 was originally estimated to be similar to the other two CCCTs approved in that docket (Franklin Farms 1, Franklin Farms 2), as it is based on the same technology and design.¹³⁸ However, on May 15, 2026, ELL filed the Quarterly Monitoring Report for 2026 in that docket, which reported a revised forecast for Waterford 5 of \$1,755 million (compared to the original estimate of \$1,079 million). The primary drivers for the increased cost when compared to the original estimate were reported to be: “Cost increases for site preparation and civil construction due to the geotechnical conditions at the site” and “escalation and increased costs for labor and subcontracted engineered equipment.”¹³⁹

Q. Other than capital cost overrun risk, do you have other concerns you would like to bring to the Commission's attention?

A. Yes. My concern is not limited to how much ratepayers overall might pay, or how much more they might pay in the event of a cost overrun; it also extends to whether residential and other existing ratepayers could be disproportionately affected if the industrial load

¹³⁵ Exhibit PDN-2, at 61 of 85.

¹³⁶ Docket No. U-37882, Direct Testimony of Norman Grunden at 20, Table 1.

¹³⁷ Docket No. U-37425, Laidley Generation and Transmission Project Confidential Quarterly Monitoring Report for 2026, Pursuant to Order No. U-37425, May 15, 2026.

¹³⁸ Docket No. U-37425, Direct Testimony of Matthew Bulpitt at 42:8-15.

¹³⁹ ELL response to Staff 2-1.

1 does not materialize as projected. In that scenario, residential and other existing
2 ratepayers would still bear the full cost of the Proposed Generators, since ELL's cost
3 recovery mechanism does not condition recovery on the underlying industrial load
4 actually materializing. And although the ESAs themselves were not provided in
5 discovery, my understanding is that they do not include financial commitments or
6 ratepayer protections commensurate with how consequential a change in that load could
7 be. As a result, the cost would fall disproportionately on residential and other existing
8 ratepayers, who did not drive the need for these units in the first place, and who will
9 likely not receive meaningful benefits in that scenario.

10 **Q. Is there any reason why ELL might be less concerned if the final costs of the**
11 **Proposed Generators turn out to be higher than currently estimated or if load does**
12 **not materialize as projected?**

13 A. Yes. Based on my understanding of the ACM and the cost recovery structure Mr.
14 Sullivan proposes, ratepayers bear most of that risk, while ELL will most likely recover
15 its costs plus a return, even if actual costs come in significantly higher than currently
16 estimated, or if the load assumed to justify these investments does not fully materialize.
17 Specifically, ELL is asking the Commission to authorize recovery of the Proposed
18 Generators' costs through the ACM "outside of the FRP sharing mechanism and outside
19 of any applicable cap."¹⁴⁰ The absence of a cap or sharing mechanism means the financial
20 consequences of that estimating uncertainty fall on customers, not ELL. Furthermore,
21 ELL's cost recovery is not conditioned on the load-growth assumptions discussed above
22 actually materializing: once the Proposed Generators are certified, ELL can largely
23 recover costs regardless of whether the specific industrial or data center loads cited to
24 justify this need come to pass, or whether the resulting portfolio still represents the best
25 value for customers. Furthermore, because recovery occurs through the FRP, these costs
26 will be reviewed through the annual evaluation process, where oversight and intervenors'

¹⁴⁰ Sullivan Direct Testimony at 23:2

ability to contest specific cost items may be more limited than a full rate case (as is generally true of rider-based recovery mechanisms).

Q. ELL argues that timely Commission action is necessary to meet the 2027 Final Notice to Proceed (“FNTP”) deadlines and avoid cost escalation.¹⁴¹ Does meeting that deadline eliminate the risk of cost overruns?

A. No. Meeting the FNTP deadline may avoid the specific cost escalation ELL attributes to Commission delay, but it does not eliminate the cost overrun risk. This risk stems from ELL’s estimates’ immaturity and from broader construction market conditions, not from Commission timing. These factors remain regardless of whether the Commission acts on ELL’s preferred schedule.

ELL’s request for “timely treatment” is not a substitute for a safeguard on cost recovery.¹⁴² Even if the Commission grants ELL’s requested schedule and the Proposed Generators avoid the delay-related costs ELL warns of, ratepayers remain exposed to the full range of other cost overrun risks. This is why, independent of the Commission’s decision on timing, I recommend that the Commission limit recovery of capital costs to a hard cap tied to the cost estimate underlying certification.

Q. Do you agree with ELL witness Mr. Plaisance’s testimony that the Monitoring Plan will give the Commission a meaningful opportunity to reconsider whether the Proposed Generators remain the best option for ratepayers if circumstances change?¹⁴³

A. No. Mr. Plaisance identifies four circumstances that might warrant cancellation of a Proposed Generator, including a systematic increase in forecasted gas costs and a change in completion or operating costs rendering the project no longer in the public interest. However, in discovery, ELL was unable or unwilling to identify what would actually trigger that analysis. When asked to specify the gas price level, cost overrun percentage,

¹⁴¹ Plaisance Direct Testimony, at 7:18-8:5.

¹⁴² Application at 19–20, section XXXIX (“Request for Timely Treatment”).

¹⁴³ Plaisance Direct Testimony, at 49:12-16.

1 or break-even threshold that would prompt reconsideration, ELL objected that the request
2 was “hypothetical” and stated that “the requested analysis has not been performed.”¹⁴⁴
3 Without defined thresholds, the Monitoring Plan's promise of continued evaluation is
4 difficult to hold ELL to in practice. And even where an analysis is eventually performed,
5 it would compare alternatives against the remaining, largely sunk cost of the Proposed
6 Generators rather than their full cost, a comparison that structurally favors continuing
7 with the Proposed Generators regardless of whether they were the right choice, since the
8 sunk portion of the investment is no longer avoidable. As a result, certification
9 substantially narrows the Commission's practical ability to protect ratepayers from the
10 risks described above. The time to scrutinize these risks is now, before certification locks
11 in sunk or otherwise unavoidable costs.

12 **C. Ratepayers bear fuel cost, supply, and policy risk for the life of the units.**

13 **Q. You state that ELL's increasing reliance on gas-fired resources escalates a number**
14 **of risks. Please elaborate.**

15 A. Because the large majority of this incremental capacity is gas-fired, ELL's ratepayers are
16 being asked to absorb a further increase in the system's dependence on a single fuel
17 source. This raises three related but distinct exposures.

18 First, **gas price volatility**: a much larger share of ELL's fleet, and a much larger share of
19 customer bills, will move with the price of natural gas than would be the case under a
20 more diversified resource mix. Gas price volatility has been particularly pronounced in
21 recent years, driven by geopolitical disruptions, growing LNG export demand, weather-
22 driven swings in regional supply and demand, and other factors that are largely outside
23 any individual utility's control, meaning ELL has little ability to mitigate this exposure
24 once it further commits its resource mix to gas.

25 Second, **fuel supply infrastructure risk**: because these units rely on the same category
26 of fuel-delivery infrastructure (interstate and intrastate pipelines), a disruption affecting

¹⁴⁴ ELL response to EDF 1-17.

1 that infrastructure, whether from weather, mechanical failure, or capacity constraints, has
2 the potential to affect multiple gas-fired units at the same time, possibly at a time when
3 the system has peak need. Even absent a material disruption, the costs of securing that
4 supply, including firm transportation, will apply across a large share of the fleet and
5 persist for the operating life of the units. Any increase in these costs will have an outsized
6 impact on the system as a whole, with ratepayers having no practical way to escape that
7 exposure once it is locked in for decades.

8 Third, **policy risk**: ELL's gas-fired units are largely subject to the same regulatory
9 exposure for carbon-emitting resources. For example, ELL witness Halland discusses the
10 potential need for the CCCTs to comply with the Environmental Protection Agency
11 ("EPA") new source performance standards and emission guidelines that are currently in
12 effect, but are being legally challenged.^{145,146} It is plausible that this or some form of
13 emissions guideline or cost for carbon-emitting generation will be adopted within the
14 operating life of these units (even if the EPA rules are eventually not implemented). ELL
15 mentions two decarbonization pathways as providing "important optionality" for these
16 units: hydrogen co-firing and carbon capture and storage.¹⁴⁷ This is a known uncertainty
17 that ELL should be hedging against, not an unforeseeable risk, and it carries outsized
18 stakes here because of how much gas-fired capacity ELL is committing to. Neither
19 compliance pathway is likely to be affordable, and either might also not be feasible at the
20 scale needed. Achieving either pathway would require far more than some "upgrades" for
21 hydrogen firing or a site that can "accommodate" CCS infrastructure, as noted in ELL's
22 testimony.¹⁴⁸ CCS would require new capture and compression equipment plus
23 underground storage. Full hydrogen firing would require significant changes to the fuel
24 supply chain: the production, transport, and storage of hydrogen, and, to be a

¹⁴⁵ New base load turbines (defined as units that are generating at least 40 percent of their maximum annual capacity, i.e., greater than 40 percent capacity factor) are subject to an initial "phase one" standard based on efficient design and operation of CC turbines; and a "phase two" standard based on 90 percent capture of CO₂ with a compliance deadline of January 1, 2032.

See EPA, Fact sheet carbon pollution standards for fossil fuel-fired power plants final rule, available at: <https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-overview.pdf>

¹⁴⁶ Halland Direct Testimony at 14:14–23.

¹⁴⁷ Pressler Direct Testimony at 5:12-13.

¹⁴⁸ Pressler Direct Testimony at 3:7-11.

1 meaningfully low-carbon fuel source, a substantial new supply of renewable or other
2 clean generation to produce that hydrogen in the first place. Importantly, the cost of either
3 pathway is not included in ELL's current cost estimate for the Proposed Generators,¹⁴⁹ so
4 if future regulations require CCS or high levels of hydrogen firing, ratepayers would face
5 this additional, unquantified but significant cost with no way to avoid or mitigate that
6 exposure once these units are built.

7 **Q. One of your concerns is that ELL's growing reliance on gas leaves customers**
8 **exposed to fuel-price volatility the Company cannot control. Are customers already**
9 **exposed to that volatility today?**

10 A. Yes, and substantially so. ELL recovers the cost of fuel from customers through its fuel
11 adjustment clause (“FAC”) rider, and that cost rises and falls with the market price of
12 natural gas. Figure 9 below shows ELL’s monthly average fuel cost alongside the Henry
13 Hub natural gas price from 2020 through mid-2026.¹⁵⁰ The two move together, and both
14 have swung sharply: Henry Hub rose from roughly \$2 per MMBtu in early 2020 to nearly
15 \$9 per MMBtu in mid-2022, fell back below \$2 in early 2024, and spiked again above \$7
16 in early 2026, with the customer fuel charge tracking each of those moves. For a
17 household consuming 1,000 kWh per month, the swing from October 2025 to February
18 2026 translated to an additional cost of \$16 in a single month.

¹⁴⁹ ELL response to Sierra 1-12, and ELL response to Sierra 1-13.

¹⁵⁰ Average fuel cost data collected from fuel adjustment reports and plotted by cost month, not filing month. ELL's billing is based on fuel and purchased power costs from two months prior. FAC reports available at <https://lpscpubvalence.lpsc.louisiana.gov/>

1

2

3 ELL's fuel costs for 2025 operations were approximately \$1.8 billion.¹⁵¹ These costs, at
4 that magnitude, move with a commodity price ELL cannot control, and the risk is borne
5 by ratepayers. For the fuel costs incurred in January and February 2026, ELL ratepayers
6 were asked to pay almost 12% more than the same months of the previous year. Adding
7 1,508 MW of gas-fired capacity, on top of ELL's already gas-heavy fleet, increases the
8 share of customer bills subject to these swings.

9 **Q. Has ELL conducted any sensitivity analysis to understand fuel price exposure under**
10 **a different gas price scenario?**

11 A. No. ELL's only gas-price sensitivity work was performed inside its economic evaluation
12 of the Proposed Generators, not as an assessment of the fuel-cost exposure ratepayers
13 would bear, and even there it was limited. As I discussed in Section V.B.4 above, ELL
14 ran a low gas price sensitivity but left the High Gas, High CO2 case blank, confirmed that
15 this case had not been run for the RFP, and declined to produce supporting analysis when
16 asked. [REDACTED]

17

18

19

¹⁵¹ This figure is the summation of line 34 of the “Monthly Cost of Fuel Adjustment Report” of the FAC filings for 2025 (cost months). That figure reflects the fuel cost of serving load in 2025; because the FAC recovers costs on a lag, it differs from the amount actually collected from customers in the same calendar year.

1 [REDACTED]
2 [REDACTED] Natural
3 gas price spikes could result in tens of millions of additional costs for ratepayers on any
4 single month.

5 **Q. Is there any reason why ELL might not be concerned with fuel price volatility and**
6 **potential increases in fuel security costs, including from increased firm**
7 **transportation?**

8 A. Yes. Fuel costs, including the costs of firm transportation, are recovered from customers
9 through ELL's FAC, with no sharing mechanism.¹⁵² If gas prices spike, or firm
10 transportation costs are higher than currently projected, those costs will generally be
11 passed through to ratepayers, subject to a subsequent review in FAC proceedings. That
12 review, however, occurs after the costs have already been incurred, and in practice may
13 not receive the same level of scrutiny as issues raised in a certification docket like this
14 one, given the practical resource constraints intervenors, and at times Commission Staff,
15 face in auditing every fuel-related cost after the fact across an entire test year (a limitation
16 that applies to cost-recovery riders generally). ELL therefore has comparatively limited
17 independent incentive to minimize fuel price and fuel security risk on customers' behalf
18 at the time these decisions are made, relative to the scrutiny available at certification.
19 That underscores the importance of scrutinizing fuel supply and transportation planning
20 now, at the certification stage in dockets like this one, where risks can be identified and
21 addressed before costs are incurred and fall on ratepayers for the next three or four
22 decades.

23 **D. ELL's system needs diversification, not additional gas-fired resources.**

24 **Q. ELL states that the Proposed Generators will “be available and quickly**
25 **dispatchable by MISO to help ensure system reliability that could be impacted by**
26 **the variability in intermittent renewable resources.”¹⁵³ Do you agree?**

¹⁵² Sullivan Direct Testimony at 15 n.12.

¹⁵³ Plaisance Direct Testimony at 44:1-4.

1 A. Not fully. System reliability can be supported by both "dispatchable" and "intermittent"
2 resources, along with the underlying transmission network. System reliability
3 encompasses two related but distinct components that ELL's argument conflates:
4 operational reliability, the ability of the grid to balance supply and demand in real time
5 and respond to contingencies; and resource adequacy, the ability of the grid to meet
6 demand with enough electricity supply, especially during peak periods and other times of
7 grid stress. Real-time renewable variability is an operational reliability concern that
8 various dispatchable technologies, not only CCCTs, can help address. On the other hand,
9 dispatchability alone does not establish resource adequacy in times of system stress.

10 To further explain, I do not dispute that gas-fired generation can support both functions,
11 or that gas-fired resources can provide benefits to a diversified portfolio. But what ELL is
12 proposing is not diversification; it is two additional large CCCTs, with inadequate
13 evidence establishing need or economic benefit, layered onto a system already
14 overwhelmingly concentrated in gas. My concern is with the marginal impact of these
15 additions on a system that is already gas-heavy: they do not meaningfully improve either
16 ELL's ability to integrate intermittent renewable resources or the resource adequacy of
17 the system; they might in fact crowd out other resources that would do so more
18 meaningfully.

19 **Q. Are CCCTs the only technology that can help with smoothing out the variability of**
20 **intermittent renewable resources?**

21 A. No. Battery storage can also complement renewable resources even more directly than a
22 CCCT can. Batteries can charge during periods of excess renewable output and discharge
23 later, smoothing the mismatch between generation and load. Because they can respond on
24 an intra-hour basis, they reduce the need to ramp thermal generation up and down,
25 without the fuel cost a CCCT carries. Each of the two load pockets ELL proposes to build
26 in already includes recently built CCCT generation that can help address renewable
27 variability, especially at the renewable deployment level planned there.

1 **Q. ELL characterizes the Proposed Generators as "dispatchable." Does that**
2 **automatically lead to a reliable or resource adequate system?**¹⁵⁴

3 A. No. Dispatchability, on its own, is an insufficient and potentially misleading criterion for
4 evaluating new resource additions: so-called "dispatchable" resources can and have failed
5 to dispatch, leading to major outages.¹⁵⁵ "Dispatchable" describes a resource's ability to
6 be turned on or ramped up and down at an operator's direction, but does not mean that
7 ability is always available. Gas-fired generation is subject to correlated outages, *i.e.*
8 multiple units failing at the same time for the same underlying reason, because they share
9 exposure to the same vulnerabilities (*e.g.* fuel supply disruptions or frozen equipment).
10 That risk is not diversifiable across a gas-heavy fleet the way it would be across a more
11 varied resource mix, and it grows more consequential as reliance on gas increases,
12 because a larger share of the fleet is exposed to the same failure mode at once.

13 **Q. Has MISO ever experienced this correlated-outage risk?**

14 A. Yes, this risk has been demonstrated repeatedly in MISO's own experience. Recent
15 winter emergencies have featured the simultaneous failure of gas-fired generation, driven
16 by fuel-supply interruptions and cold-weather equipment failure.

17 During Winter Storm Uri in February 2021, MISO South, the region that includes ELL,
18 declared maximum generation emergencies and shed firm load. Across the affected
19 system, freezing issues (44.2%) and fuel-supply issues (31.4%) together caused roughly
20 three-quarters of all unplanned unit outages, derates, and failures to start, and gas-fired
21 units alone accounted for approximately 58% of all generator outages.¹⁵⁶

22 During Winter Storm Elliott (December 2022), which struck the Eastern Interconnection
23 including MISO, freezing and fuel issues caused 55% of all outages, derates, and failures

¹⁵⁴ Plaisance Direct Testimony at 4:11-15.

¹⁵⁵ Adefunke Sonaike, Reality Check: Dispatchability and Reliability Are Not the Same Thing,” RMI, January 8, 2025, <https://rmi.org/resources/reality-check-dispatchability-and-reliability-are-not-the-same-thing/>

¹⁵⁶ Federal Energy Regulatory Commission & North American Electric Reliability Corporation, The February 2021 Cold Weather Outages in Texas and the South-Central United States: FERC, NERC and Regional Entity Staff Report (Nov. 2021), <https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and>.

1 to start. Natural gas fuel issues represented 83% of all outages attributable to fuel
2 problems, and gas units made up nearly half of all units that failed.¹⁵⁷

3 Furthermore, while the bulk power system held in Winter Storm Fern (January 2026),
4 gas-fired generation underperformed relative to its accredited capacity, producing less
5 than half of expected output in the hardest-hit Plains region, even as renewable resources
6 delivered more than twice their accredited capacity in both Southwest Power Pool
7 (“SPP”) and MISO.¹⁵⁸

8 Gas-fired generation’s correlated-failure risk grows as a larger share of the fleet becomes
9 concentrated in these resources. I do not dispute that gas-fired generation can support
10 resource adequacy; it does so in many systems. But ELL is proposing a portfolio so
11 heavily reliant on gas that the marginal contribution of each incremental gas-fired
12 resource to system reliability is lower than ELL suggests, particularly as that
13 concentration crowds out other resource types that would otherwise diversify the
14 portfolio and reduce correlated exposure.

15 **VII. A Staged, Diversified Portfolio Would Better Match ELL’s Evolving Need and**
16 **Reduce Customer Risk.**

17 **Q. Throughout your testimony, you talk about resource strategies that could result in**
18 **lower risk, lower cost portfolios that ELL failed to explore in the planning and**
19 **procurement of the CCCTs. What would these portfolios consist of?**

20 A. There are resource options, including EE; DR and load flexibility; transmission solutions
21 and GETs; customer-sited generation; and incremental renewable energy and energy
22 storage, including both short- and long-duration storage, that could help ELL meet its

¹⁵⁷ Federal Energy Regulatory Commission & North American Electric Reliability Corporation, *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott* (Nov. 2023), https://www.nerc.com/globalassets/our-work/reports/event-reports/winter_storm_elliott_report.pdf.

¹⁵⁸ Michael Goggin, Grid Strategies LLC, *Winter Storm Fern Shows the Value of Transmission and Diverse Generation*, Niskanen Center (Mar. 25, 2026), <https://gridstrategiesllc.com/wp-content/uploads/Niskanen-Grid-Strategies-Fern-Report.pdf>.

1 projected load with low risk in planning, execution, and ongoing operations, and at lower
2 overall cost to ratepayers.

3 These resources are low risk in planning because their value does not depend on a single
4 assumption playing out as forecast. EE, for example, is never stranded; it permanently
5 reduces demand either avoiding new generation or avoiding existing fossil fuel
6 generation if load does not materialize as expected. DR and load flexibility primarily
7 reflect operational adjustments and thus does not lead to stranded investment. Energy
8 storage can deliver operating value to the system, such as energy arbitrage or ancillary
9 services, even if the specific capacity need does not materialize as assumed. These
10 resources are also modular and scalable, with some not requiring the upfront capital
11 commitment large CCCTs do, preserving optionality and flexibility as uncertainty around
12 planning conditions unfolds. Several can also be deployed on a shorter timeline than a
13 new CCCT, improving grid reliability even in the near term. And when accounting for
14 both the construction and operating costs of the resources, such a portfolio can be lower
15 cost.

16 **A. Resource Need**

17 **Q. Please summarize the resource need that this alternative portfolio would have to**
18 **meet.**

19 A. According to ELL's most recent analysis, including Project Evest and its associated
20 generation resources,¹⁵⁹ without Westlake and WF6 the need is as follows:

¹⁵⁹ ELL response to Staff 1-94, "BP26 and Evest L&Cs_HSPM," "Evest L&C (Change Case)" tab (Summer).

1
2

3

4

B. Alternative Portfolio

5

Q. Have you constructed an alternative portfolio?

6

A. Yes. I have put together an illustrative near-term alternative portfolio that includes the resources discussed above (and below in more detail), to show the feasibility of an alternative approach that would result in lower cost and reduced risk, including execution risk in the near term, and ongoing costs and risks in the longer-term: fuel price, supply, and policy risk, and, most importantly, stranded-cost risk.

9

10

11

The portfolio provides equivalent or higher capacity (Summer SAC) and energy than the Proposed Generators and consists of:

12

13

- The achievable potential for EE, DR, and customer-sited solar and batteries under the high-adoption scenario in ELL's DSM Potential Study;

14

15

- Transmission solutions and GETs, conceptually, although these are not reflected as MW additions;

16

- 1 • The interconnection of solar resources at the Little Gypsy point of interconnection
2 (“POI”) as soon as possible and solar plus storage at the Nelson 6 site upon its
3 retirement.
- 4 • Other customer-sited and self-supply resources offsetting the need for incremental
5 utility-owned resources (assumed to reflect 5 percent of the incremental industrial
6 demand).¹⁶⁰

7 Although the illustrative alternative portfolio described above does not include onshore
8 wind, wind is a strong complementary resource: its generation profile, particularly in the
9 evening and overnight hours, differs meaningfully from solar's, and it can therefore
10 contribute diversification benefits. I would recommend that ELL include wind to the
11 extent feasible in a portfolio of this kind. The alternative portfolio presented here is
12 illustrative rather than exhaustive.

¹⁶⁰ Alternatively, this could be viewed as a slower load materialization rate. Based on Figure 4 which shows the BP26-to-BP22 divergence and the ELL large-load pipeline, in 2032 this gap is already █ percent. Based on my experience reviewing large-load interconnection and contracting pipelines, a reduction of this magnitude is very conservative. For example, Dominion Energy Virginia's own forecast validation shows that even fully executed ESAs, which under Dominion's three-stage contract structure seem to carry a significantly higher degree of financial and infrastructure commitment than ELL's ESAs, are included in Dominion's demand forecast at only about a portion of their contracted capacity (78 percent in 2030). My recommendations include periodic progress reports of the large-load pipeline, so the Commission can stay informed of how this percentage evolves as ELL's own large-load contracts mature.

Letter from Stanley L. Blackwell, Director – Data Center Practice, Dominion Energy, to PJM Load Analysis Team, at 3 (Jan. 6, 2026) (forecast graph comparing executed contract capacity to forecasted demand), available at: <https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/dominion-documentation.pdf>

Table 5: Proposed Generators vs Alternative Portfolio¹⁶¹

	Summer								
	2026	2027	2028	2029	2030	2031	2032	2033	
Load Requirement									
Existing & Planned (no NL6 conversion, WF6, Westlake, or other gas-fired resource w/o filing)									
Owned Resources + Affiliate PPAs									
Third Party PPAs									
LMRs									
Planned Resources									
Total									
Surplus/Deficit									
Westlake									
WF6									
NL 6 conversion									
Total									
Surplus/Deficit									
EE									
DR									
Customer Resources - Solar									
Customer Resources - Battery									
5% private generation									
Solar									
Solar + Storage									
Total									
Surplus/Deficit									

The alternative portfolio provides more capacity than the Proposed Generators in all years studied. It delivers equivalent amounts of energy in 2031 and beyond, but higher levels of energy in the years before that, resulting in additional benefits and reduced reliance on MISO.

1. Energy Efficiency

Q. Please describe the role of energy efficiency in the alternative portfolio.

A. EE is typically the lowest-cost resource available to reduce both energy and peak demand, and it should be a foundational part of any staged, diversified, low-cost, low-risk portfolio. Because EE reduces consumption at the point of use, it also avoids the line losses that would otherwise be incurred in delivering that energy from a central

¹⁶¹ Solar resources, both customer-sited and utility-owned, are shown as nameplate capacity in their respective rows but are excluded from the total MW capacity values. This is not because solar resources would not receive a capacity credit (in fact the 2023 IRP assigns a 48% capacity credit, 2023 IRP, footnote 15) but rather an overly conservative approach.

1 generating station. It also defers the system's need for additional generating capacity and
2 the associated planning reserve margin that incremental load would require. EE reduces
3 the underlying need itself rather than adding a new resource to meet it, and it does so
4 without the fuel-price, policy, or construction risk that accompanies a new gas-fired unit,
5 and without the risk of being left stranded. Finally, EE delivers non-energy benefits for
6 participating customers, including enhanced comfort, improved health and safety, and
7 increased home value.

8 **Q. How much does EE cost, and is it cost-effective?**

9 A. EE is highly cost-effective. Cost-effectiveness is assessed by comparing the value of a
10 program's benefits to its costs, where a ratio above one indicates that benefits exceed
11 costs. ELL's draft DSM potential study prepared by ICF for the 2027 IRP ("DSM
12 Potential Study") reports that ELL's EE portfolio would achieve a Total Resource Cost
13 ("TRC") ratio of 4.6 in the Reference case and 4.0 under the High adoption case,
14 meaning the quantified energy and capacity benefits would result in savings roughly four
15 times the total costs incurred, counting both utility and participant costs. The levelized
16 cost of this EE portfolio is \$0.02/kWh, or \$20/MWh.¹⁶² By comparison, the fuel cost
17 alone for CCCT generation is projected to exceed \$30/MWh,¹⁶³ without even accounting
18 for fixed or variable O&M, fixed fuel demand charges, or the capital cost of constructing
19 the units. EE can therefore result in significant savings. As a low-cost, low-risk option,
20 opportunities for EE should be exhausted before turning to new generation.

21 **Q. What level of EE are you proposing to be included in the alternative portfolio? Is**
22 **this level achievable?**

23 A. According to the 2027 DSM Potential Study, under a high-adoption scenario, ELL's EE
24 programs could deliver approximately 195 MW of peak capacity and 745 GWh of
25 cumulative energy savings by 2030, growing to approximately 250 MW and 960 GWh by

¹⁶² LPSC Docket No. U-37764, ICF, ELL 2027 IRP — Energy Efficiency, Demand Response, and DER Potential Study (Draft Results) (Mar. 6, 2026), at 21 (portfolio-level TRC).

¹⁶³ Assuming a gas price of \$5/MMBtu and a heat rate of 6.4 MMBtu/MWh for a generic CCCT.

2031, and approximately 470 MW and 1,845 GWh by 2035.¹⁶⁴ These figures represent achievable potential in ELL's own service territory, i.e. they are economic compared to the resources they can help avoid and can be practically implemented. It is worth noting that this is not a maximum boundary of what is available and could be achieved: higher potential could be pursued through different incentives and program design. Importantly, because EE is modular and incremental, it can begin delivering these savings in the near term rather than on the multi-year construction timeline the Proposed Generators require.

Given the cost savings and other EE benefits, an optimal portfolio should include all ELL-identified achievable EE potential.

Table 6: EE Potential (high adoption) based on ELL's DSM Potential Study¹⁶⁵

	2027	2028	2029	2030	2031	2032	2033
EE (MW)	40	90	145	195	250	305	360
EE (MWh)	140,000	335,000	530,000	745,000	960,000	1,160,000	1,375,000

2. Demand Response

Q. Please describe the role of DR in the alternative portfolio.

A. DR addresses peak demand needs by shifting or curtailing customer load during system peak conditions, rather than by adding new supply-side capacity. It can be deployed at a fraction of the cost and lead time of new generation, and unlike a new CCCT, it carries no fuel-price, policy, or construction risk. The DSM Potential Study is not limited to traditional residential DR; for commercial and industrial customers, it separately models an “Interruptible” load category alongside options such as auto demand response, aggregated capacity, direct load control, and customer-sited battery storage.¹⁶⁶ This

¹⁶⁴ LPSC Docket No. U-37764, ICF, ELL 2027 IRP Energy Efficiency, Demand Response, and DER Potential Study Draft Results, March 6, 2026, slide 14 (Cumulative MWh Savings Forecast) and slide 15 (Cumulative Summer MW Savings Forecast) (High Case).

¹⁶⁵ ELL 2027 IRP – EE, DR, and DER Potential Study, Draft Result, ICF, March 6, 2026, at 14-15. The annual values shown are estimated from the cumulative savings figures presented graphically in the presentation; the presentation reports specific values only for select years and does not include a supporting data table of annual values.

¹⁶⁶ LPSC Docket No. U-37764, ICF, ELL 2027 IRP — Energy Efficiency, Demand Response, and DER Potential Study (Draft Results) (Mar. 6, 2026), at 23 (Programs and Scenarios).

1 reflects some of the load flexibility large customers can provide, whether through a
2 traditional DR program, acceptance of non-firm service, or registration as a Demand
3 Response Resource–Type I (“DRR-I”) with MISO, which allows retail customers to offer
4 their interruptible or curtailable load directly into the MISO market as a resource.

5 There are two reasons why DR is particularly valuable in addressing ELL's need in this
6 case, including the capacity need created by the retirement of the Little Gypsy units.
7 First, some large loads can offer significant levels of flexibility. In fact, some of the
8 industrial and data center ESAs already include provisions for load flexibility, although
9 ELL has not disclosed the specific form or magnitude of that flexibility, and has not
10 accounted for it in its resource planning (see Section IV). Second, and more generally,
11 utilities plan for their systems' peak demand plus a reserve margin, a level that is only
12 reached, if at all, for a few hours each year. Although many of the new large loads
13 driving ELL's claimed need have high load factors, meaning they run at a fairly steady
14 level rather than sharply peaking, they are being added to a system that otherwise has its
15 own peaks. Rather than building new capacity that would sit largely unused outside those
16 few peak hours, DR can be deployed specifically to meet that narrow peak need or even
17 serve as reserve, increasing the utilization of the existing system instead of adding new
18 infrastructure to serve it. Targeted interruptible or flexible-load commitments from those
19 specific customers could therefore address a meaningful share of the projected capacity
20 need they are creating at lower cost and risk than new generation.

21 **Q. How much does DR cost, and is it cost-effective?**

22 A. DR, like EE, is highly cost-effective. The DSM Potential Study reports that ELL's DR
23 portfolio would achieve a TRC ratio of 3.36 in the Reference case and 3.24 under the
24 High adoption case.¹⁶⁷ The levelized cost of the DR portfolio is \$68/kW-yr for residential
25 programs and \$50/kW-yr for commercial and industrial. By comparison, ELL assumed a
26 levelized [REDACTED] cost (as a benchmark in the economic evaluation) of \$ [REDACTED]/kW-yr in 2031,

¹⁶⁷ LPSC Docket No. U-37764, ICF, ELL 2027 IRP — Energy Efficiency, Demand Response, and DER Potential Study (Draft Results) (Mar. 6, 2026), at 29 (portfolio-level TRC).

escalating to [REDACTED] by 2060.¹⁶⁸ As a low-cost, low-risk option, opportunities for DR should be exhausted before turning to new capacity.

Q. What level of demand response are you proposing be included in the alternative portfolio? Is this level achievable?

A. Based on the DSM Potential Study, under a high-adoption scenario DR across all sectors could reach approximately 260 MW by 2030 and approximately 425 MW by 2031, growing to approximately 1,268 MW in 2046.¹⁶⁹ The resource therefore builds over the planning horizon: while its near-term contribution is more modest, it grows to a substantial share of system peak over time, and can be scaled as load materializes. Whether this potential is achieved depends heavily on program design and on whether ELL actually pursues it.

Given the cost savings and other benefits, an optimal portfolio should include all ELL-identified achievable DR potential.

Table 7: DR Potential (high adoption) based on ELL's DSM Potential Study¹⁷⁰

	2027	2028	2029	2030	2031	2032	2033
DR (MW)	30	80	150	260	425	625	830

Q. Do you have reason to believe that additional DR or load flexibility is achievable?

A. Yes. ELL's most recent Load and Resources analysis, including the Evest load, shows an [REDACTED]
[REDACTED]
[REDACTED] Furthermore, across all DR

¹⁶⁸ ELL response to Sierra 1-1 Add 2, "2024 ELL CCCT RFP Economic Evaluation Model – Updated Analysis 260206_HSPM," "Assumptions" tab, "BP26 ELL Levelized CT w/ Hydrogen (UCAP)" (Capacity Value, \$/kW-Yr.).

¹⁶⁹ ICF, ELL 2027 IRP Energy Efficiency, Demand Response, and DER Potential Study Draft Results, March 6, 2026, at 24 (Summer MW Savings – All Sectors).

¹⁷⁰ ELL 2027 IRP – EE, DR, and DER Potential Study, Draft Result, ICF, March 6, 2026, at 24. The annual values shown are estimated from the cumulative savings figures presented graphically in the presentation; the presentation reports specific values only for select years and does not include a supporting data table of annual values.

¹⁷¹ ELL response to Staff 1-94, "BP26 and Evest L&Cs_HSPM," "Evest L&C (Change Case)" tab (Summer), "LMRs," 2029.

options for industrial customers, a cumulative potential of 500 MW is reported for 2036. This is similar, if not less than the industrial DR options included in the 2022 Potential Study for 2032,¹⁷² a study developed prior to the significant increase in industrial load growth, indicating that load flexibility from these customers might not be appropriately reflected in the ELL values in Table 6.

3. Customer Resources

Q. What are customer-sited resources?

A. Customer-sited resources are generation, storage, or controllable end-use assets located at, or dedicated to, an individual customer's premises. This includes rooftop or on-site solar, battery storage, combined heat and power/cogeneration, backup generation, and other resources a customer may own, lease, or contract to serve its own load, provide backup or resiliency, or in some cases contribute capacity or energy back to the grid.

Q. What role could behind-the-meter (“BTM”) solar and storage play in the alternative portfolio?

A. The DSM Potential Study evaluates the potential levels of battery storage, solar, and combinations of the two. The results are particularly low, and the draft results do not provide further detail beyond the modeled figures. A higher level of BTM solar and storage deployment should be explored by ELL and the Commission. For purposes of the alternative portfolio, I have only included the levels identified in the DSM Potential Study.

¹⁷² ICF Resources, LLC, *Entergy Louisiana Draft Potential Study Results* (Jan. 24, 2022), available at <https://www.entergyloisiana.com/wp-content/uploads/2022-01-24-ICF-Draft-Potential-Study-Results.pdf>.

Table 8: Customer Solar and Battery Potential (high adoption) based on ELL’s DSM Potential Study¹⁷³

	2027	2028	2029	2030	2031	2032	2033
Customer-sited Solar (MW)	111	128	147	169	192	217	245
Customer-sited Battery (MW)	0	1	2	5	8	11	16

Q. What about customer-sited resources for industrial customers?

A. Separately from the solar and battery options identified in the DSM Potential Study, there's an ongoing rulemaking in LPSC Docket No. R-37905, evaluating private use electrical networks (“PUENs”) to enable generation to serve new large loads, principally data centers and industrial facilities, looking to locate in Louisiana.

A PUEN, as defined in Senate Bill 490, is "generation, energy storage, and related electrical facilities" that are located on contiguous, adjacent, or commonly controlled property, are primarily dedicated to serving the electricity requirements of one or more identified load customers, and deliver electricity through privately owned electrical facilities.

Q. What is CHP, and how does it relate to a PUEN?

A. CHP (combined heat and power, or cogeneration) captures the waste heat from onsite power generation and uses it to serve a facility's existing thermal load. This achieves a combined efficiency of roughly 75%, compared to roughly 50 percent when power and heat are supplied separately, electricity from the grid and heat from an onsite boiler.¹⁷⁴ CHP is only beneficial, however, to the extent a facility has a genuine, sustained thermal load to absorb the waste heat. Additionally, CHP is not zero-emission, since it still

¹⁷³ ELL 2027 IRP – EE, DR, and DER Potential Study, Draft Result, ICF, March 6, 2026, at 46. Customer-sited solar photovoltaic (“PV”) is the sum of residential and commercial and industrial (“C&I”) values in MW_{AC}, for battery storage, this include residential batteries paired with PV installations as well and paid and standalone C&I systems, “power” capacity is shown.

¹⁷⁴ U.S. Department of Energy, Office of Manufacturing and Energy Supply Chains, "Combined Heat and Power Basics," available at <https://www.energy.gov/cmei/ito/combined-heat-and-power-basics>.

combusts natural gas. CHP is already used at customer sites in Louisiana, putting otherwise-wasted industrial heat to use. It could be incorporated as part of a PUEN or structured as a Qualifying Facility under the Public Utility Regulatory Policies Act.

Q. What level of industrial-scale customer-sited generation, including CHP, is currently available, and could it offset planned utility generation?

A. Louisiana already has a substantial existing base of industrial self-generation. Entergy's own filings in the R-37905 docket cite approximately 6,700 MW of existing industrial cogeneration, and approximately 4,000 MW of LNG-related generation.¹⁷⁵ Incremental CHP or other resources could be developed as new industrial load comes online, and they could reduce or defer the need for new utility-built capacity to serve the same loads.

Q. What is your recommendation to the Commission with respect to the consideration of customer-sited resources in its deliberations for this docket?

A. I would recommend not assuming or ruling out any specific level of private resources from new industrial customers when deliberating in this docket. The rulemaking in R-37905 remains in progress, with a Draft Rule expected in mid-August 2026 and a Commission decision expected later in the year. Certifying the Proposed Generators before the rulemaking concludes risks double-building: the utility constructs new generation while industrial customers separately build their own, both aimed at covering part of the same need.

This risk is sharpened by the mismatch between the length of the ESAs and the life of the assets built to serve them. Many of the ESAs underlying ELL's claimed need are for only [REDACTED] years or a similar term,¹⁷⁶ while the CCCTs proposed to meet that need are expected to operate for significantly longer. If the R-37905 rulemaking produces a PUEN framework that lets some of these same large industrial or data-center customers shift to

¹⁷⁵ LPSC Docket No. R-37905, Entergy Louisiana, LLC's Responses to Commission Staff's First Set of Requests for Information, July 17, 2026.

<https://lpscpubvalence.lpsc.louisiana.gov/portal/PSC/ViewFile?fileId=LXE7Yv8Uw8w%3D>

¹⁷⁶ Sierra 3-11, attachment 'RL-U37853-00SIE003-L011_PART_A_HSPM_MW_Update (without customer names) HSPM.'

self-supply once their ESA term expires, ELL could be left recovering the cost of CCCT capacity built for load that has since left the system, stranding that capacity for the remaining decades of its useful life, with the cost falling on remaining ratepayers.

4. Transmission Solutions and Grid Enhancing Technologies

Q. What is the role of transmission solutions, and what recent events illustrate the need for them in ELL's region?

A. Transmission solutions, targeted investments that relieve the constraints limiting power delivery into a load pocket, can address reliability needs by strengthening the grid rather than by building new generation behind the constraint. Recent events in ELL's region illustrate why this matters. On May 25, 2025, Southeast Louisiana experienced a power system emergency that required last-resort actions to protect the regional electric grid. According to MISO, the event was driven by a convergence of challenges, including the continued outage of the critical Nelson-Richard 500kV transmission line, the unavailability of more than 50 percent of local generation due to outages and limited transmission import capability.¹⁷⁷ These challenges culminated in MISO declaring a Transmission System Emergency and directing controlled load shed in the affected area (approximately 600 MW).

In response, MISO is conducting a South Load Pocket Risk Assessment, together with the LRTP process for the South region expected to take about three years with initial solution options identified and announced in 2027 and finalization of the study in 2028.¹⁷⁸ MISO's efforts aim to determine the optimal actions, including both transmission and generation options, that can address reliability concerns.¹⁷⁹

¹⁷⁷ MISO, May 25 Load Shed Event Report, August, 2025.
<https://cdn.misoenergy.org/May%2025%20Load%20Shed%20Event%20Report%20-%20August%202025711584.pdf>. At 3

¹⁷⁸ MISO, Transmission Planning, E-RSC Working Group Open Meeting (Oct. 7, 2025),
<https://cdn.misoenergy.org/20251007%20ERSC%20WG%20Item%2004%202025%20South%20Transmission%20Planning721588.pdf>.

¹⁷⁹ MISO, Entergy Region State Committee, November, 2025.
<https://cdn.misoenergy.org/20251111%20ERSC%20Item%2008%20Transmission%20Planning726733.pdf>

Q. What could the role of GETs in the alternative portfolio be?

A. GETs are hardware and software tools, such as dynamic line ratings, power flow control devices, and topology optimization, that increase the usable capacity of existing transmission lines rather than requiring new ones. GETs expand the potential of the transmission already in place, at a fraction of the cost and lead time of new construction. As a result, GETs can lower operating costs (through reduced production costs) and capital costs (through deferred or avoided transmission upgrades) and can ease the integration of new resources.

These are proven, in-use technologies. PPL Electric deployed dynamic line ratings on three transmission lines in 2022, allowing it to eliminate or defer transmission line upgrades and additions.¹⁸⁰ A 2021 Brattle study of the Southwest Power Pool found that GETs would allow Kansas and Oklahoma to integrate an additional 2,670 MW / 8,776 GWh of renewables, more than double the amount without them, while yielding \$175 million per year, resulting in a simple payback of less than a year.¹⁸¹ Reconductoring existing lines with advanced conductors can likewise up to double a line's capacity at less than half of the cost of new lines,¹⁸² and utilities are pursuing these approaches at scale: in October 2025, the U.S. Department of Energy closed a \$1.6 billion loan guarantee to AEP Transmission Company LLC to increase its transmission capacity by roughly 70 percent via reconductoring or rebuilding transmission lines.¹⁸³

¹⁸⁰ PPL Electric Utilities, *PPL Electric Utilities' first-of-its-kind innovation improves reliability, reduces costs*, <https://news.pplweb.com/2023-07-11-PPL-Electric-Utilities-first-of-its-kind-innovation-improves-reliability-reduces-costs> (Jul. 11, 2023).

¹⁸¹ T. Bruce Tsuchida et al., *Unlocking the Queue with Grid-Enhancing Technologies*, Brattle, https://watt-transmission.org/wp-content/uploads/2021/02/Brattle_Unlocking-the-Queue-with-Grid-Enhancing-Technologies_Final-Report_Public-Version.pdf90.pdf (Feb. 1, 2021).

¹⁸² Researchers at the University at California, Berkeley and GridLab found that “reconductoring enables nearly four times as much transmission capacity...by 2035.” Energy Institute at Haas, *Accelerating Transmission Expansion by Using Advanced Conductors in Existing Right-of-Way* at 5, <https://haas.berkeley.edu/wp-content/uploads/WP343.pdf> (Feb. 2024). In another study, GridLab concluded that “[a]dvanced conductors can up to double line capacity within existing rights-of-way (ROW)” and “[r]econductoring projects typically cost less than half the price of new lines for similar capacity increases.” GridLab, *Reconductoring With Advanced Conductors Can Accelerate the Rapid Transmission Expansion Required for a Clean Grid* at 3, https://www.2035report.com/wp-content/uploads/2024/06/GridLab_2035-Reconductoring-Technical-Report.pdf (Apr. 2024).

¹⁸³ U.S. Department of Energy, DOE Closes \$1.6 Billion Loan Guarantee to AEP Transmission (Oct. 16, 2025).

1 Applied here, GETs could reduce the new transmission investment this docket
2 contemplates and, more importantly, allow a more economic generation portfolio by
3 easing the same load-pocket constraints that contributed to the May 25 event, more
4 directly and at lower cost than building gas-fired generation behind those constrained
5 paths.

6 **Q. What is your recommendation with respect to transmission solutions and GETs to**
7 **address the identified need?**

8 A. I have two recommendations. First, the Commission should direct ELL to wait for the
9 results of MISO's South Load Pocket Risk Assessment and South LRTP study before
10 committing to new generation intended to address the same reliability concerns those
11 studies are specifically designed to evaluate. Second, ELL should study and file with the
12 Commission a report evaluating the role of GETs in alleviating the constraints in those
13 load pockets in the near term, improving grid reliability and reducing costs for ratepayers.

14 **5. Solar and Storage**

15 **Q. Please describe the role of energy storage and solar-plus-storage in the alternative**
16 **portfolio.**

17 A. Storage, including storage paired with solar, can provide dispatchable capacity during
18 peak hours without ongoing fuel costs or fuel-price exposure. Storage resources charge
19 during periods of lower demand or higher renewable output and discharge during peak
20 periods, providing many of the same reliability benefits ELL attributes to the Proposed
21 Generators, but without the associated fuel-supply or commodity-price risk. Pairing
22 storage with solar further hedges against future gas price volatility, since a share of the
23 underlying energy is then provided by a zero-fuel-cost resource.

24 **Q. ELL is already procuring solar and storage resources. Do you have any concerns**
25 **about its approach?**

26 A. Yes. I recognize that ELL is currently pursuing solar and storage resources, but as
27 expressed earlier, I am concerned that the fragmentation of its procurement into separate

RFPs, and the specific sequence of its applications, prioritizes the certification of CCCTs in a way that could eventually crowd out other resources. For example, comparing ELL's BP26 Load and Resources analysis (with Evest) to the resources it has actually applied for before the Commission, the only resources I could not map to a specific certification docket [REDACTED]

[REDACTED].¹⁸⁴ [REDACTED]
[REDACTED].

Q. Are there other options that ELL should explore for the interconnection of solar and storage resources?

A. Yes. There are also some options that ELL has not fully evaluated, including solar, energy storage, and paired additions at sites where interconnection capacity may be readily available. While ELL has stated in discovery that it does not currently have surplus interconnection capacity at “the sites relevant in this docket,”¹⁸⁵ its system-wide evaluation of this question remains ongoing.¹⁸⁶ Given that ELL's own evaluation is still underway, this option should be investigated further.

Similarly, the interconnection rights freed by the retirement of the Nelson 6 unit could be transferred to a solar-plus-storage resource through the generator replacement process.

Even for the Little Gypsy units, which ELL states do not have surplus interconnection capacity, a similar approach could still be evaluated: solar could interconnect behind the same POI as an energy resource,¹⁸⁷ increasing the utilization of the POI¹⁸⁸ and adding energy to the system earlier rather than waiting for the units' eventual retirement and

¹⁸⁴ ELL response to Staff 1-95(a)(iii) and ELL response to Staff 1-94.

¹⁸⁵ ELL response to Sierra 1-15.

¹⁸⁶ ELL response to Sierra 2-9.

¹⁸⁷ Duke Energy has used this type of screening in its own resource planning in North and South Carolina. Specifically, Duke evaluated its CT sites by reviewing five years of historical CT site capacity factors and site function to determine whether a given CT plant was a candidate for adding a surplus solar resource behind the same POI. For sites that passed this screen, the surplus solar addition served primarily as an energy resource while the CT continued performing its capacity and reliability role. 2025 Carolinas Resource Plan, Appendix K, at 25. Available at: <https://www.duke-energy.com/our-company/about-us/irp-carolinas/2025-crp>

¹⁸⁸ Little Gypsy 2 operated at a capacity factor of 15 percent in 2025, and Little Gypsy 3 operated at 5 percent, leaving their POI significantly underutilized during most of the year. Generation data from S&P Capital IQ.

1 replacement with a CCCT. The solar resource could later become part of that unit's
2 permanent replacement (and could be paired with energy storage).

3 **Q. Is there evidence supporting inclusion of additional solar in the alternative**
4 **portfolio?**

5 A. Yes. To my understanding ELL's Geaux Green Option shows waitlisted demand of
6 1,326.8 MW as of December 2025, customers who sought a subscription to ELL's
7 renewable portfolio who were accommodated in part or not at all. While this waitlist
8 reflects demand for a green-tariff subscription, not a specific resource, it demonstrates
9 that customers are interested in clean energy above a level ELL can accommodate.¹⁸⁹

10 Furthermore, ELL's system is planned to have 1,190 MW of solar by 2029,¹⁹⁰ of which
11 Bogalusa West (200 MW) and Cypress Harvest (200 MW) have been certified through
12 the 3,000 MW alternative process in Docket U-36697,¹⁹¹ leaving a significant gap of that
13 authorized 3,000 MW target that ELL has not yet procured. Separately, 1,500 MW of
14 solar and/or solar-plus-storage has been allocated to serve Laidley's load in Docket U-
15 37425. The 1,500 MW are *in addition* to the 3,000 MW of solar resources approved by
16 the Commission in Order No. U-36697.¹⁹²

17 However, beyond the named solar projects (amounting to 1,190 MW of nameplate
18 capacity), ELL's most recent BP26 Load and Resources table, [REDACTED]

¹⁸⁹ LPSC Docket Nos. R-28271 Subdocket B, U-35916, U-36190, and U-36697, Annual Report of Entergy Louisiana, LLC on the Renewable Energy Pilot Program (Mar. 2, 2026), at 18–20.

¹⁹⁰ Entergy, Entergy Renewable Portfolio (data as of July 2026), <https://www.entergy.com/wp-content/uploads/15/Entergy-renewable-portfolio.pdf>

¹⁹¹ Votaw Solar and Segno Solar have not been certified as ELL system resources; both were first offered to a customer under a green tariff option, with ELL to seek certification as system resources only if that customer does not proceed.

LPSC Docket Nos. R-28271 Subdocket B, U-35916, U-36190, and U-36697, Annual Report of Entergy Louisiana, LLC on the Renewable Energy Pilot Program (Mar. 2, 2026), at 15.

¹⁹² LPSC Docket No. U-37425, Application of Entergy Louisiana, LLC for Approval of Generation and Transmission Resources Proposed in Connection with Service to a Significant Customer Project in North Louisiana, Including Proposed Rider, and Request for Timely Treatment at 5, section V (Oct. 30, 2024).

1 [REDACTED]

2 [REDACTED].¹⁹³

3 This leaves a gap that is potentially higher than 4 GW of solar, combining the 2,600 MW
4 remaining under ELL's own 3,000 MW authorization with the 1,500 MW allocated to
5 Laidley (depending on how much of that 1,500 MW is ultimately built as solar generation
6 versus battery storage).

7 **Q. What incremental level of solar and storage resources are you proposing be**
8 **included in the alternative portfolio?**

9 A. The alternative portfolio assumes 2,000 MW of solar, a portion of which can be
10 interconnected at the Little Gypsy POI and other existing sites through surplus
11 interconnection as soon as possible, as well as at the Nelson 6 site upon its retirement
12 (using Nelson's existing interconnection rights through the generator replacement
13 process), providing energy to the system and reducing reliance on MISO market
14 purchases; that solar could become part of the permanent replacement for the site. It also
15 assumes 350 MW of solar paired with storage . Little Gypsy's Network Resource
16 Interconnection Service (“NRIS”) for Units 3 and 4 totals [REDACTED] MW ([REDACTED] MW and [REDACTED]
17 MW, respectively), and Nelson's NRIS is [REDACTED] MW.¹⁹⁴

18 Costs are assumed to follow the cost and performance assumptions in ELL's 2027 IRP
19 Data Assumptions Supplemental filing.¹⁹⁵ Recent actual battery costs, however, appear
20 lower than those assumptions: the Bogalusa and Cypress Creek battery projects ELL
21 applied to build in Docket No. U-37882 were priced at \$367 million for 200 MW/800
22 MWh,¹⁹⁶ or approximately \$1,835/kW, roughly 10 percent below the \$2,031/kW that
23 ELL's IRP assumptions show for a comparable 4-hour lithium-ion battery.

¹⁹³ ELL response to Staff 1-94, attachment “Staff 1-94 BP26 and Evest L&Cs_HSPM.”

¹⁹⁴ ELL response to EDF 1-19(a), EDF 1-19(a) 2020-2025 ICAP SAC LG2 LG3 N6_HSPM.

¹⁹⁵ LPSC Docket No. U-37764, ELL, 2027 IRP Data Assumptions Supplemental Filing, at 29, also available at:
https://www.entergyloUISIANA.com/wp-content/uploads/2027-ELL-IRP-Data-Assumptions-Supplemental_2026_04_24_PUBLIC.pdf

¹⁹⁶ LPSC Docket No U-37882, Direct Testimony of Laura K. Beauchamp, Table 1: Resources in Evest Application
LPSC Docket No U-37882, Direct Testimony of Laura K. Beauchamp, Table 9: Capacity Construction Estimates.

C. Benefits of the Alternative Portfolio

Q. Why is a staged portfolio less risky than approving the Proposed generators now?

A. A staged portfolio preserves optionality that an irreversible commitment does not. Locking in both plants now forces customers to absorb, upfront, every uncertainty that hasn't yet resolved: whether the load fully materializes, how policy and market conditions shift, where gas commodity and delivery costs land, and whether future regulatory requirements change the economics of these units mid-life. By certifying these units right now, the associated risks are shifted to ratepayers, who could be left holding cost obligations for decades for resources built to serve a transitional need (see Figure 10).

A staged approach does not forego capacity or create reliability concerns. On the contrary, it captures savings that are available now, since EE and DR measures begin delivering benefits as soon as programs launch. It also prioritizes resources, including energy storage and solar, that perform well under a broad range of future conditions and therefore carry less risk of future regret. It includes customer resources and load flexibility that can avoid the need for incremental capacity that would otherwise sit underutilized. And it allows for transmission solutions that deliver near-term benefits while unlocking more resource options and lower-cost portfolios over the long term.

If the staged portfolio proves too conservative, ELL can still add capacity, with more resource options available (including CCCTs) and greater clarity by that point. If, on the other hand, the two-CCCT commitment leads to overbuilding, a scenario that I consider very likely, ratepayers will be stuck paying for oversized, underutilized, or stranded assets for decades to come.

Q. How does the alternative portfolio compare to the Proposed Generators in terms of cost?

A. Given the near-term focus of the staged approach I recommend, I compared the annualized costs for 2032 (a representative year after both CCCTs would be in service) for the alternative portfolio and the Proposed Generators, rather than a full 30-year revenue-requirement analysis. For the alternative portfolio, I applied the unit-cost

assumptions described above (EE at \$20/MWh, DR at \$50/kW) and assumed that customer-sited solar and battery would cost the utility 70 percent of the corresponding utility-scale resource. For utility-scale solar and solar-plus-storage, I used costs from ELL's 2027 IRP assumptions.¹⁹⁷

For the Proposed Generators, I annualized the \$4.1 billion in total added capital cost,¹⁹⁸ together with O&M and fixed fuel demand charges from ELL's own projections, and separately calculated fuel costs for 2032. This capital-cost calculation is simplified relative to a full revenue-requirement analysis but is intended to be broadly comparable to the methodology used for the alternative portfolio. Consistent with my assumption of 5 percent of private generation, I applied that same assumption to reduce the Proposed Generators' expected 2032 generation and associated fuel costs, so that both portfolios are evaluated against the same load assumption.

On this basis, the Proposed Generators' 2032 annualized cost is approximately \$[REDACTED] million, while the alternative portfolio, built up from the unit costs described above applied to the same near-term quantities, costs approximately \$[REDACTED] million less on an *annual* basis, without even accounting for revenues from excess capacity and energy that the alternative portfolio delivers compared to the Proposed Generators in most years. It is also important to note that the alternative portfolio provides both a lower starting cost and cost stability over the long term, as it is significantly less exposed to fuel price fluctuations.

This cost advantage would grow further if fuel prices increase, or if load does not materialize as projected, or if large load customers pursue higher levels of self-supply or customer-sited resources. As a point of reference, the levelized cost of EE is \$20/MWh, while the levelized cost of CCCT generation depends on its assumed capacity factor: assuming the Proposed Generators' capital cost per the Application and generic fuel costs (without adding fixed and variable O&M or fixed fuel demand costs), the levelized cost

¹⁹⁷ ELL 2027 IRP Data Assumptions at 24. <https://www.entergyloouisiana.com/wp-content/uploads/Entergy-Louisiana-2027-IRP-Data-Assumptions.pdf>

¹⁹⁸ See Table 1

1 is \$70/MWh at a 70 percent capacity factor, rising to \$84/MWh if the units instead serve
2 lower load at a 50 percent capacity factor.¹⁹⁹

3 Although this is a simplified calculation, it illustrates that a materially lower-cost, lower-
4 risk path is available to meet near-term needs without committing ratepayers to the
5 Proposed Generators.

6 **VIII. Recommendations and Conclusion**

7 **Q. What do you recommend to the Commission?**

8 A. Based on my review and analysis, I recommend that the Commission deny certification
9 of both Waterford 6 and Westlake at this time, given the deficiencies in ELL's need and
10 economic analyses, and ELL's failure to show these units are the lowest reasonable cost
11 resources.

12 **Q. Do you have additional recommendations for the Commission?**

13 A. Yes. In the event that ELL resubmits an application for the Proposed Generators, or asks
14 for the Commission's reconsideration, I recommend a set of threshold conditions to
15 ensure existing ratepayers are protected, together with additional analyses the
16 Commission should require. The threshold conditions address the core deficiencies I
17 identify in this testimony regarding need, alternatives, and ratepayer safeguards; without
18 them, the record cannot support a conclusion that the Proposed Generators or other
19 resources are the lowest reasonable cost option. The supporting analyses, by contrast,
20 would strengthen and inform the Commission's review and it reflects information that
21 could reasonably continue to develop in parallel with, or shortly following, a renewed
22 application.

¹⁹⁹ Based on a heat rate of 6.03 MMBtu/MWh (Annual Technology Baseline, from National Laboratory of the Rockies, formerly National Renewable Energy Laboratory, available at https://data.openei.org/files/6006/2024_v3_Workbook.xlsx) and a \$6.1/MMBtu Henry Hub Price for 2032 (EIA, 2026 AEO, available at <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2026®ion=0-0&cases=cb2026&start=2025&end=2050&f=A&linechart=cb2026-d021826b.3-13-AEO2026~cb2026-d021826b.60-13-AEO2026&ctype=linechart&sourcekey=0>)

Q. What are the threshold conditions?

I recommend the following threshold conditions prior to any reconsideration of the Proposed Generators:

- a) ELL has conducted a competitive, all-source procurement rather than relying on the CCCT-only RFP. Given the additional time prior to reconsideration, ELL can conduct an all source RFP according to the MBM order.
- b) The rulemaking in Docket No. R-37905 has concluded, so self-supply potential for large loads is known before ELL commits ratepayers to utility-built capacity for the same load. A final rule is expected later this year.
- c) ELL has committed to firm retirement dates for Little Gypsy 2 & 3 and Nelson 6, avoiding the risk that ratepayers pay for both the retiring units and their replacements at the same time.
- d) ELL presented an updated Load and Resources analysis, reflecting the updated load, but also the load flexibility customers have agreed to provide, as well as the expected level of customer resources.
- e) ELL has demonstrated efforts to achieve EE and DR resources at the high-adoption level identified in its own DSM Potential Study. These are lower-cost resources that ELL's own analysis found achievable, so pursuing them at the identified level reduces the amount of new, higher-cost generation that ratepayers would otherwise have to fund.
- f) MISO's South Load Pocket Risk Assessment and LRTP study are completed and reflected in the record. The LRTP process is expected to take approximately three years, with initial solution options identified and announced in 2027 and the study finalized in 2028. These studies could identify transmission solutions that unlock additional, lower-cost resource options for ELL; committing to the Proposed Generators before they're complete risks locking ratepayers into a more expensive portfolio than a transmission-enabled alternative might soon make available.

Q. What additional supporting analyses do you recommend?

A. I recommend the following conditions and supporting analyses, each aimed at protecting affordability for ratepayers by ensuring the Commission has the information it needs for its decision and for continued regulatory oversight:

g) ELL has completed its system-wide surplus interconnection capacity evaluation, including the option of interconnecting energy resources at existing CT sites. As this docket itself demonstrates, interconnection capacity is valuable; if surplus capacity exists at other sites, it could host lower-cost solar or storage resources instead of requiring new generation and the added interconnection costs that come with it.

h) ELL has presented a documented methodology for its large load forecasting (used to inform the identified need in a future application), including the discount factors applied at each pipeline stage, and commits to ongoing reporting to the Commission on the status of that pipeline. The Commission cannot verify whether the claimed need is being conservatively or aggressively forecasted without visibility into how pipeline projects are screened and discounted over time, and ongoing reporting allows it to catch and correct issues before ratepayers are locked into costs based on an outdated or overstated projection.

i) ELL has shown consideration of the impact on existing ratepayers if the large loads underlying its claimed need do not materialize as forecast, documented through sensitivity or other analyses in the next certification application, or has found a way to contractually address that risk. Without such consideration, the customers driving the claimed need bear little of the associated risk, while ratepayers are left holding the cost of stranded or underutilized capacity if that load fails to materialize as projected.

j) ELL has studied and filed a report on the role of GETs in relieving transmission constraints and the savings they could deliver. GETs can often relieve transmission constraints at a fraction of the cost of new generation or transmission

1 infrastructure, so ratepayers should not be asked to fund new capacity before
2 lower-cost transmission solutions to the same constraint have been ruled out.

3 **Q. Do you have a recommendation in the event the Commission is inclined to certify**
4 **one of the Proposed Generators at this time?**

5 A. Yes. If the Commission is inclined to certify one of the Proposed Generators now, I
6 recommend that certification be conditioned, at minimum, on ELL satisfying threshold
7 conditions (c) and (e) above: firm commitments to retire Little Gypsy 2 & 3 and Nelson
8 6, and demonstrated efforts to pursue EE and DR at the high-adoption level identified in
9 ELL's own DSM Potential Study. These two conditions are the most readily achievable in
10 the near term, and they address the most immediate risks to ratepayers: that ELL is paid
11 for both retiring and replacement capacity at the same time, and that lower-cost DSM
12 resources are bypassed in favor of new generation.

13 I recommend that the Commission require all of the remaining threshold conditions,
14 together with the supporting analyses, to be satisfied before it considers certifying the
15 second Proposed Generator. Conditions (a) through (c) depend on processes that will take
16 time, including MISO's three-year South Load Pocket Risk Assessment and LRTP study,
17 an all-source procurement, and conclusion of the R-37905 rulemaking. However, a
18 second CCCT carries an even higher risk of overbuilding, so the Commission should
19 require a complete record (including the results of processes already underway), and has
20 options to do so, before committing ratepayers to a second, multi-decade capital
21 investment.

22 **Q. Do you have any recommendations about cost recovery if the Commission certifies**
23 **any of the Proposed Generators?**

24 A. Yes. Independent of the above, if any of the Proposed Generators are certified, the
25 Commission should limit recovery of capital costs to a hard cap tied to the cost estimate
26 underlying certification.

27 **Q. Does that conclude your testimony?**

1 A. Yes.

AFFIDAVIT

NOW BEFORE ME, the undersigned authority, personally came and appeared, Maria Roumpani, who after being duly sworn by me, did depose and say:

That the above and foregoing is her sworn testimony in this proceeding and that she knows the contents thereof, that the same are true as stated, except as to matter and things, if any, stated on information and belief, and that as to those matters and things, she verily believes them to be true.

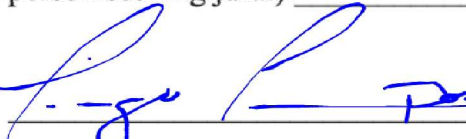
Maria Roumpani

Maria Roumpani

City/County of Suffolk city

Commonwealth of Virginia

The foregoing instrument was subscribed and sworn before me this 30 day of
July, 20 26 by Maria Roumpani (name of
person seeking jurat) _____

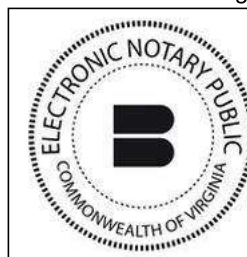


Notary Public's signature

Notary registration number: 00353607

My commission expires: 06/29/2029

Notarized online using audio-video communication technology



Tiago Campos
Electronic Notary Public
Commonwealth of Virginia
Commission #: 00353607
Commission Expires: 06/29/2029



Maria Roumpani

Founding Partner, mrroumpani@currentenergy.group

Professional Summary

Maria is an expert in energy system planning with deep experience in quantitative modeling and economic analysis of grid planning and operations issues. She focuses on the economic and technical analysis of resource procurement, grid operations, and ratepayer impact questions, with experience in capacity expansion optimization, production cost simulation, and the development of customized analytical tools and frameworks. Maria has submitted expert testimony and comments on integrated resource planning, generation plant economics, unit commitment and dispatch practices, power cost analysis, and demand-side management plans. Her clients include consumer advocates, public interest organizations, energy project developers, government agencies, and large energy buyers.

Education

PhD, Management Science & Engineering

Stanford University, 2018

MSc, Electrical and Computer Engineering

National Technical University of Athens, 2009

Work Experience

Founding Partner, Current Energy Group (May 2024 – Present)

- Founding partner specializing in the economic and technical analysis of grid planning and operations issues, including capacity expansion, production cost, and energy storage dispatch modeling.

Founder, ELO Engineering Consulting (March 2024 – May 2024)

- Conducted analysis on energy policy and economic issues.

Technical Director | Strategen Consulting (2018 – March 2024)

- Led firmwide technical and economic modeling and analysis to support consulting engagements. Specialized in the use of modeling tools to inform grid planning and decarbonization issues.

Research Assistant | Precourt Institute for Energy, Stanford University (2011 – 2017)

- Conducted research in a wide range of topics, from game theoretical approaches in electricity markets to behavioral economics.

Researcher | Energy, Economics, & Environment Modeling laboratory, National Technical University of Athens, (2009-2010, 2015)

- Contributed to the development of long-term energy planning models.
- Developed a wholesale electricity market competition model.

Expert Testimony

2025 Biennial Consolidated Carbon Plan and Integrated Resource Plan of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC

on behalf of the Southern Alliance for Clean Energy, the Sierra Club, and Vote Solar
North Carolina Utilities Commission
Docket No. E-100, Sub 207

[Testimony](#)

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Application to Engage in a Business Combination

on behalf of the Sierra Club
Public Service Commission of South Carolina
Docket No. 2025-230-E

[Testimony](#)

Virginia Electric and Power Company's Application for a Certificate of Public Convenience and Necessity to construct and operate the Chesterfield Energy Reliability Center

on behalf of Advanced Energy United
Virginia State Corporation Commission
Case No. PUR-2025-00037

[Testimony](#)

Georgia Power Company's 2025 Integrated Resource Plan

on behalf of Georgia Conservation Voters Georgia
Georgia Public Service Commission
Docket No. 56002

[Testimony](#)

Virginia Electric and Power Company's 2024 Integrated Resource Plan

on behalf of Advanced Energy United
Virginia State Corporation Commission
Case No. PUR-2023-00066

[Testimony](#)

East Kentucky Power Cooperative, Inc. Application for Approval of Demand Side Management Tariffs

on behalf of Joint Intervenors Appalachian Citizens' Law Center, Kentuckians for The Commonwealth, and Mountain Association
Kentucky Public Service Commission
Case No. 2024-00370

[Testimony](#)

NV Energy and Sierra Pacific Power Company 2025-2044 Integrated Resource Plan

on behalf of Advanced Energy United
Public Utilities Commission of Nevada
Docket No. 24-05041

[Testimony](#)

Duke Energy Carolinas and Duke Energy Progress 2023 Integrated Resource Plans

on behalf of Sierra Club, South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Upstate Forever, and Vote Solar
Public Service Commission of South Carolina
Docket No. 2023-8-E & No. 2023-10-E

[Testimony](#)

Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, and Duke Energy Progress,

on behalf of the Southern Alliance for Clean Energy, Sierra Club, Natural Resources Defense Council, and North Carolina Sustainable Energy Association
North Carolina Utilities Commission
Docket E-100, Sub 190

[Testimony](#)

Annual Review of Base Rates for Fuel Costs of Dominion Energy South Carolina, Inc.

on behalf of the South Carolina Office of Regulatory Staff
Public Service Commission of South Carolina
Docket No 2023-2-E

[Testimony](#)

Annual Review of Base Rates for Fuel Costs of Duke Energy Progress, LLC

on behalf of the South Carolina Office of Regulatory Staff

Public Service Commission of South Carolina

Docket No 2023-1-E

[Testimony](#)

Virginia Electric and Power Company 2023 Integrated Resource Plan

on behalf of Advanced Energy United

Virginia State Corporation Commission

Case No. PUR-2023-00066

[Testimony](#)

PacifiCorp's Transition Adjustment Mechanism

on behalf of Sierra Club

Oregon Public Utilities Commission

Docket No. UE 420

[Testimony](#)

DTE 2022 IRP

on behalf of the Michigan Energy Innovation Business Council

Michigan Public Service Commission

Case U-21193

[Testimony](#)

Duke Energy Carolinas and Duke Energy Progress 2022 Carbon Plan

on behalf of the Tech Customers

North Carolina Utilities Commission

Docket E-100, Sub 179

[Testimony](#)

Public Service Company of Colorado

on behalf of Sierra Club

Colorado Public Utilities Commission

Proceeding No. 21A-0141E

[Testimony](#)

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Louisiana Public Service
Commission Staff

Question No.: STAFF 1-94

Part No.:

Addendum:

Question

Please provide ELL's most recent BP26 Load and Capability Report, and any subsequent updates, revisions, internal planning versions, or analyses reflecting updated load or resource assumptions used for planning or decision-making purposes. This would include updated analysis to plan for large load customers such as Laidley, Evest, Hyundai, etc. With respect to each version provided:

- a. Identify all individual load additions included in the annual load projections, including the projected MW and MWh for each such load by year;
- b. For each of the following projects, state whether the load is included in the projections and, if so, for each provide the complete projected ramp (MW and MWh) by year until projected steady state load is achieved:
 - i. Laidley (Meta) project;
 - ii. Evest (Meta) project;
 - iii. Hyundai project (publicly disclosed March 2025);
 - iv. Shintech Louisiana project (publicly disclosed March 2026);
 - v. Hut 8 / FluidStack project (publicly disclosed December 2025);
 - vi. Air Liquide project (publicly disclosed June 2025);
 - vii. Any other block load additions separately considered by ELL
- c. For any of the above loads not included in the projections, explain the basis for exclusion and identify whether ELL has evaluated such load for planning purposes outside of the Load and Capability Report;
- d. For any of the above loads not included in the projections of the Load and Capability Report, but for which ELL has developed or considered a projected ramp (MW and MWh) by year for any planning, modeling, or decision-making purpose, provide such projected ramp.
- e. Provide the annual total system load projections both:

- i. Including all of the above projects; and
 - ii. Excluding each project individually; and provide the resulting difference in total system load (MW and MWh) for each case by year.
 - f. Provide all supporting workpapers and calculations in Excel format with formulas intact, including any models or inputs used to generate the projections.
 - g. To the extent the Company has performed any scenario analyses or sensitivity analyses related to the inclusion or exclusion of any of the resources or loads identified above, please provide all such analyses, including any analyses evaluating variations in load growth, retirement assumptions, resource additions, or timing of such resources
-

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. Subject to and without waiving the objections, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material (“HSPM”) and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

Please see the HSPM attachment provided in the Company’s response to Staff 1-94, BP26 and Evest L&Cs_HSPM.

- a. See attached workpapers in Excel file Staff 1-94 BP26 ELL PART_AB_HSPM.xlsx showing the list of all individual load additions included in the annual load projections, including the projected MW and MWh for each such load by year.
- b. See attached workpapers in Excel file Staff 1-94 BP26 ELL PART_AB_HSPM.xlsx showing which of the listed projects were included in projections, including projected ramp (MW and MWh) by year until steady state load is achieved.
- c. The Air Liquide project (publicly disclosed June 2025) from the list was not included in the projections because ELL did not know about this project at the time the Business Plan was developed.

- d. No additional projected ramps exist.
- e. See attached HSPM workpaper Excel file Staff 1-94 BP26 ELL PART_AB_HSPM.xlsx.
- f. See the workpapers referenced in this response.
- g. No scenario analysis or sensitivity analysis was performed related to the inclusion of any of the resources or loads identified above.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Southern Renewable
Energy Association

Question No.: SREA 1-7

Part No.:

Addendum:

Question:

Please refer to Plaisance Direct at pp. 19-20 discussing ELL's capacity needs in reference to new loads associated with the Hyundai Motor Group, CF Industries, and the Woodside Energy Group, and at p. 20 line 13 noting that these projects collectively represent of [REDACTED] of incremental load growth.

- a. Please provide the annual load projected for the Hyundai Motor Group project by year from 2027 to 2037, differentiated between fully contracted load and noncontracted load.
 - b. Please provide the annual load projected for the CF Industries project by year from 2027 to 2037, differentiated between fully contracted load and non-contracted load.
 - c. Please provide the annual load projected for the Woodside Energy Group project by year from 2027 to 2037, differentiated between fully contracted load and noncontracted load.
-

Response:

The Company objects to this request to the extent it seeks customer-specific information, as such information is highly sensitive and confidential and the release of such information could cause undue harm to both the Company and the specific customers whose information is requested. The Company further objects to the request for customer-specific information to the extent it seeks information that could violate the provisions of the Commission's General Order in LPSC Docket No. R-29213. The Company further objects to the request as vague and ambiguous, because the response references a difference "between fully contracted load and non-contracted load", which distinction is unclear. Subject to and without waiving the foregoing, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material ("HSPM") and will be produced only to the appropriate Reviewing

Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

See the HSPM attachment titled “SREA 1-7 BP26 ELL PART_ABC_HSPM.” The specific customers are anonymized as Project G, Project WG, and Project X. Further, the Projected Ramp MWh by year listed in the attachment are not probability-weighted and instead are based on the relevant customers’ full contracted load.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Environmental Defense
Fund

Question No.: EDF 1-5

Part No.:

Addendum:

Question:

Is the load forecast used for the economic evaluation in AURORA in this docket the same as BP26? If not, please provide a detailed explanation of any differences.

Response:

ELL incorporates in full the General Objections served with these Requests. The Company further objects to the request as the reference to “economic evaluation” is vague and ambiguous, including because AURORA is used for production cost modeling, and the economic evaluation is not performed in AURORA. The Company further objects to the request for an exhaustive list of any differences. Subject to and without waiving the objection, the Company responds as follows.

The AURORA modeling was done based on BP25 rather than BP26, because BP25 was the operative business plan at the time the economic evaluation of the RFP results was performed. Notably, BP26 was used in preparing the supply plan, as reflected in the Direct Testimony of Michael J. Plaisance. Further responding, please see the Company’s response to EDF 1-10.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
Requesting Party: Sierra Club

Question No.: SIERRA 1-1

Part No.:

Addendum:

Question:

Please provide workpapers and modeling files supporting the Company's proposed Combined Cycle Combustion Turbines ("CCCT") units in this matter, including (not limited to) all input files, output files, and pre- or post-processing of those inputs and outputs for all resource portfolios, scenarios, sensitivities, and years modeled, in machine-readable Excel format.

Response:

The Company objects to the "Instructions" included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the statement that the requests are "continuing in nature" such that the Company should supplement under certain circumstances set forth in the "Instructions", as such statement and instruction seek to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. The Company further objects to this request as overbroad, vague, and ambiguous. Subject to and without waiving the objections, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material ("HSPM") and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

See the HSPM attachments.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 1-4

Part No.:

Addendum:

Question:

Please provide ELL's most recent peak load and energy forecasts, the peak load and energy forecasts used in this filing (if different), and all peak load and energy scenarios used to evaluate the proposed CCCTs, in machine-readable Excel format.

- a. For each load and energy forecast, please provide:
 - i. The annual amount of load and energy that is due to large loads that have signed agreements or contracts with the Company.
 - ii. The annual amount of load and energy that is due to potential large load customers, including supporting analysis for how this amount was determined.
-

Response:

The Company objects to the "Instructions" included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the statement that the requests are "continuing in nature" such that the Company should supplement under certain circumstances set forth in the "Instructions", as such statement and instruction seek to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. Subject to and without waiving the objections, the Company responds as follows.

See the attached HSPM workpapers in Excel file RL-U37853-00SIE001-L004_HSPM.xlsx showing ELL's most recent approved peak load and energy forecasts used to evaluate the proposed CCCTs.

- a. See the attached HSPM workpapers in Excel file RL-U37853-00SIE001-L004_PART_A_HSPM.xlsx showing the annual amount of load and energy that is due to large loads that have signed agreements as well as load and energy that is due to potential large load customers.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 1-25

Part No.:

Addendum:

Question:

Please provide ELL's most recent final, unredacted Integrated Resource Plan, including all appendices and exhibits and all supporting workpapers.

Response:

The Company objects to the "Instructions" included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the statement that the requests are "continuing in nature" such that the Company should supplement under certain circumstances set forth in the "Instructions", as such statement and instruction seek to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. The Company further objects to this request as overbroad and unduly burdensome to the extent it seeks "all supporting workpapers." Subject to and without waiving the objections, the Company responds as follows.

Please see the public and HSPM attachments.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Environmental Defense
Fund

Question No.: EDF 1-3

Part No.:

Addendum:

Question:

Provide the following to allow comparison between the Final 2023 IRP load forecast and the BP26/AURORA load forecast:

- a) The Final 2023 IRP peak load (MW) and energy (MWh) forecast by customer segment (residential, commercial, industrial, and other) for each year modeled;
 - b) The BP26 peak load (MW) and energy (MWh) forecast by customer segment for the same years; and
 - c) The difference between the two forecasts by customer segment for each year, explaining any differences.
-

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving these objections, the Company responds as follows:

Information responsive to this request has been designated as Highly Sensitive Protected Material (“HSPM”) and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

- a. See the HSPM attachment RL-U37853-00EDF001-L003_ab_HSPM.xlsx, tabs named BP22 Class Peaks and BP22 Class Energy.
- b. See the HSPM attachment RL-U37853-00EDF001-L003_ab_HSPM.xlsx, tabs named BP26 Class Peaks and BP26 Class Energy.

- c. The Company objects to the request to the extent it seeks an exhaustive listing of each of the referenced differences and to the extent it seeks information that is equally available to the requester based on review of available documents. Subject to and without waiving the foregoing, the largest single driver of differences of MWh volumes in the two forecasts is the new, large industrial customers in BP26. These types of customers, along with the change concerning wholesale energy from BP22 (which is now part of the retail industrial energy), comprise 95-100% of the energy differences between the two forecasts.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Environmental Defense
Fund

Question No.: EDF 1-9

Part No.:

Addendum:

Question:

For each large industrial customer whose load is included in the BP26 forecast, state whether ELL has executed an ESA or other binding load commitment with that customer. If yes, provide the ESA, identify the date of execution, the contracted peak demand, and the contracted in-service date, including the projected load ramp. If no ESA exists, describe the basis on which the load was included in the forecast and the probability assigned to that load materializing on the assumed schedule.

Response:

ELL incorporates in full the General Objections served with these Requests. The Company further objects to the request as the reference to “contracted in-service date” is vague and ambiguous. The Company further objects to this request as seeking information that is irrelevant and/or not reasonably calculated to lead to the discovery of admissible evidence, including with respect to the request for contract execution dates. Subject to and without waiving the objections, the Company responds as follows:

Information responsive to this request has been designated as Highly Sensitive Protected Material (“HSPM”) and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

See the Company’s response to Sierra 2-8 for responsive information concerning the estimated total MW size of each individually modeled large industrial customer project in BP26, the status of the project at the time of BP26 development (Signed ESA, Announced, etc.), and the projected load ramp reflected as annual MWh included in the BP26 forecast on a probability-weighted basis. Please also see the Company’s Addendum to its response to Sierra 3-11. See also the Company’s response to EDF 1-2(e) for a description of why the non-contracted load was included. At present, only [REDACTED] does not yet have a signed ESA; all other projects listed in Sierra 2-8 have signed ESAs. As with any other individually modeled project without a signed ESA, the ISD for

██████ that was used in the forecast is based on information from the relevant customer at the time of the forecast development.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the Second Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 2-8

Part No.:

Addendum:

Question:

[REDACTED]

a. [REDACTED]

b. [REDACTED]

c. [REDACTED]

d. [REDACTED]

e. [REDACTED]

f. [REDACTED]

g. [REDACTED]

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to this request to the extent it seeks information that was not used in evaluating the Proposed Generators, as such request is overbroad and seeks information that is irrelevant and/or not reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving the foregoing, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material (“HSPM”) and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

- a. The Company objects to this request as vague, ambiguous, and overbroad, including in particular because the request does not specify any specific, alleged discrepancy at issue. Subject to and without waiving the foregoing, the referenced requests sought different information.
- b. See the HSPM attachment “RL-U37853-00SIE001-L004 PART A HSPM” provided in the Company’s response to Sierra 1-4, specifically column G. ED Pipeline Customer ID 3598 is the only customer to date without a signed agreement.
- c. The Company objects to the request as overbroad and as seeking information that is irrelevant and/or not reasonably calculated to lead to the discovery of admissible evidence. The Company further objects to this request as seeking customer-specific information that, if released, would carry a high risk of causing undue harm to both the Company and each customer’s competitive positions. The Company further objects to the request to the extent it seeks information that could violate the provisions of the Commission’s General Order in LPSC Docket No. R-29213.
- d. See the HSPM attachment “RL-U37853-00SIE002-L008_PART A HSPM”, which is an updated version of “RL-U37853-00SIE001-L004 PART A HSPM” that was produced in response to Sierra 1-4, and which contains information responsive to this request in column G.
- e. See the HSPM attachment “RL-U37853-00SIE001-L004 PART A HSPM” provided in the Company’s response to Sierra 1-4, specifically column G. ED Pipeline Customer ID 3598 is the only customer to date in the referenced file without a signed agreement.

- f. All customers identified in HSPM attachment “RL-U37853-00SIE001-L004 PART A HSPM” were included load forecasting.
- g. There is no formally defined threshold for what constitutes a “large load.” For forecasting purposes, a 10 MW guideline is commonly used to differentiate small and large industrial loads.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the Third Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 3-11

Part No.:

Addendum:

Question:

Please update

Response:

ELL incorporates in full the General Objections served with these Requests. The Company further objects to this request as seeking irrelevant information and/or information that is not reasonably calculated to lead to the discovery of admissible evidence. The Company also objects to this request as seeking customer-specific information that, if released, would carry a high risk of causing undue harm to both the Company and each customer's competitive positions. The Company further objects to the request to the extent it seeks information that could violate the provisions of the Commission's General Order in LPSC Docket No. R-29213.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Environmental Defense
Fund

Question No.: EDF 1-2

Part No.:

Addendum:

Question:

For each large industrial customer whose load is included in the Company's Business Plan 2026 ("BP26") forecast and/or the AURORA model, provide:

- a) A copy of any executed Electric Service Agreement ("ESA") or other binding load commitment between ELL and that customer or its affiliates;
 - b) If an ESA exists, the peak demand (MW) and annual energy (MWh) specified in the ESA for each year of the agreement term;
 - c) If an ESA exists, whether it specifies any level of demand response or load flexibility, and if so, please explain the terms;
 - d) If an ESA exists, a comparison of the annual peak demand and annual energy (load ramp schedule) in the ESA against the values included in the BP26 forecast and the AURORA model, and an explanation of any differences; and
 - e) If no ESA exists for a particular customer, identify the basis on which that customer's load was included in the BP26 forecast and the AURORA model.
-

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving these objections, the Company responds as follows:

Information responsive to this request has been designated as Highly Sensitive Protected Material ("HSPM") and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

- a. See the Company's objections in response to Sierra 1-5 and 2-8.
- b. Please see the attachment provided in response to Sierra 2-8 for information concerning the peak demand (MW). ESAs do not specify annual energy (MWh).
- c. Please see the Company's Addendum to its response to Sierra 2-8.
- d. Please see the response to sub-part (b). With the exception of [REDACTED] [REDACTED] ent provided in response to Sierra 2-8, all other prospective large industrial loads included in the hourly load forecasts are probability weighted as to their maximum MW and therefore have lower MW levels in the forecast than the levels in the ESAs. However, and as further clarification, the column titled "Total Load MW" in Sierra 2-8 represents maximum MW for each of the referenced customers, which are not probability-weighted.
- e) [REDACTED] referenced in the attachment to Sierra 2-9 currently does not have a signed ESA. That project was included on a probability-weighted basis using an estimated MW size and start date that came from conversations between ELL and the customer.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 1-6

Part No.:

Addendum:

Question:

For all firm contracts that ELL has signed with prospective large load customers in the past year, please provide the following information (to the extent possible, e.g. redacting customers' names if necessary) for each prospective customer:

- a. The anticipated level of seasonal peak demand of each customer by year
 - b. The anticipated level of capacity that the customer would provide, i.e. self-supply, and the type and capacity of resource(s) provided.
 - c. The term length of the agreement in years
 - d. The minimum levels of energy and/or demand that the customer is required to use
 - e. The customer's type of industry
 - f. Any load flexibility or demand-side measures that the customer has agreed to implement
 - g. The current status of the project
 - h. Whether the project has been included in load forecasts used in this filing—and what level of annual peak load and energy was included.
-

Response:

The Company objects to the "Instructions" included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the statement that the requests are "continuing in nature" such that the Company should supplement under certain circumstances set forth in the "Instructions", as such statement and instruction seek to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. The Company

further objects to this request as overbroad and as seeking information that is irrelevant and/or not reasonably calculated to lead to the discovery of relevant evidence. The Company further objects to the extent this request seeks customer-specific information that, if released, would carry a high risk of causing undue harm to both the Company and each customer's competitive positions. The Company further objects to the request to the extent it seeks information that could violate the provisions of the Commission's General Order in LPSC Docket No. R-29213. Subject to and without waiving the objections, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material ("HSPM") and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

- a. Please see the HSPM and AEO attachments, which sets forth the relevant customers' current projected load. Please note that one of the specified amounts has been marked as Attorneys' Eyes Only ("AEO").
- b. The Company objects to this request as seeking irrelevant information, objectionable customer-specific information, and information that is uniquely in the possession of customers whose identities are confidential.
- c. Please see the HSPM attachment.
- d. The Company objects to this request as seeking irrelevant and objectionable customer-specific information.
- e. Please see the HSPM attachment.
- f. Please see the HSPM attachment.
- g. The Company specifically objects to this request as vague and ambiguous. Subject to and without waiving the foregoing objections, each of the customers whose information is included in the HSPM attachment has executed an ESA with the Company.
- h. Please see the HSPM attachment.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Environmental Defense
Fund

Question No.: EDF 1-12

Part No.:

Addendum:

Question:

Has ELL conducted any analysis to quantify the bill impact for other ratepayers or serving the load for the Hyundai steel mill, the CF Industries ammonia facility, and the Woodside LNG facility. If yes, please provide. If not, please explain why.

Response:

ELL incorporates in full the General Objections served with these Requests. The Company further objects to this request as seeking information that is irrelevant and/or not reasonably calculated to lead to the discovery of admissible evidence. The Company further objects to the request to the extent it mischaracterizes and/or misinterprets the testimony in this matter. Subject to and without waiving these objections, the Company responds as follows:

ELL has not conducted any analysis to quantify the bill impacts described in the request. ELL does not calculate the bill impacts for other ratepayers to serve a particular customer on an individual basis. ELL's line extension policy under its Terms and Conditions filed with the LPSC serves to ensure that provision of service to new customers does not unduly burden its existing ratepayers.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 1-15

Part No.:

Addendum:

Question:

Has the Company considered surplus interconnection resources that could use existing interconnection rights?

- a. If so, please provide the capacity, resource type, and location of resources being considered.
 - b. If not, please explain why not.
-

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the statement that the requests are “continuing in nature” such that the Company should supplement under certain circumstances set forth in the “Instructions”, as such statement and instruction seek to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. Subject to and without waiving the objections, the Company responds as follows.

As to the sites that are relevant in this docket, the Company does not have surplus interconnection capacity at either plant site. The Company is currently evaluating the feasibility of such resources across its system; however, the Company’s evaluation is in its early stages and is ongoing.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 1-14

Part No.:

Addendum:

Question:

Has the Company developed cost estimates for gas conversion of any of its coal units?

- a. If so, please provide the capital (including pipeline costs) and operating cost estimates for each converted unit.
 - b. If not, please explain why not.
-

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the directive that “these requests are continuing so as to require supplemental responses” as such directive seeks to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. The Company further objects to this request on the grounds that it seeks information that is irrelevant and not reasonably calculated to lead to the discovery of relevant, admissible, evidence. Subject to and without waiving the objections, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material (“HSPM”) and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

A preliminary cost estimate has been compiled for the conversion of the Nelson 6 coal plant to utilize natural gas as a fuel source. This estimate, compiled in 2019 and

Question No.: SIERRA 1-14

generically converted to 2026\$, reflects roughly [REDACTED] for the conversion cost. However, this cost reflects a previous design per industry standards at the time of development that is no longer recommended by the Original Equipment Manufacturer. [REDACTED]
[REDACTED]

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Environmental Defense
Fund

Question No.: EDF 1-16

Part No.:

Addendum:

Question:

In his February 2026 Direct Testimony (see Answer to Q30), Michael J. Plaisance states that “unit-deactivation dates have been modified [from BP24] to balance ELL's ability to meet its energy and capacity needs with achieving customer affordability.”

- a) Please provide the assumed deactivation dates for Little Gypsy Units 2 and 3 and Nelson Unit 6 in BP24 versus BP26.
- b) Please explain what specific factors caused ELL to modify each deactivation date.
- c) Please provide any analysis comparing the cost to ratepayers of continuing to operate Little Gypsy Units 2 and 3 and Nelson Unit 6 beyond their BP24 deactivation dates versus procuring replacement resources on the BP24 timeline.

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving these objections, the Company responds as follows:

- a. Assumed planning deactivation dates were as follows:

	BP24	BP26
Little Gypsy 2	5/31/2028	5/31/2030
Little Gypsy 3	5/31/2028	5/31/2030
Nelson 6	5/31/2028	Assumed to convert to a gas-fired resource and operate as such on 6/1/2028, after the cessation of coal-firing at this resource in 2/29/2028

- b. The Company's perspective on load growth has gradually changed from BP24 (which was developed in mid-2023) to BP26, with a consistent upward trend in peak demand and energy consumption observed in the load forecast during that time period. With this increase in perspective on load growth, the Company has over the past two years explored various options to shore up ELL's capacity position in response to the need to reliably serve increased levels of customer load. The extension of the Little Gypsy 2 and 3 units and the ability to extend the operations of the Nelson 6 resource were part of the tools in the long-term resource planning toolkit employed by the Company in this new growth environment and were reflected in BP26.
- c. The Company objects to subpart (c) of the request as vague and ambiguous. Subject to and without waiving the objection, the Company responds that no such analysis was performed for Little Gypsy 2 & 3. The Company is evaluating the cost to convert Nelson 6 from coal to gas but has not completed an economic evaluation comparing that cost to other alternatives.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the Second Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 2-6

Part No.:

Addendum:

Question:

[REDACTED]

- a. [REDACTED].
- b. [REDACTED].
- c. [REDACTED]

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. Subject to and without waiving the objections, the Company responds as follows.

- a. “Sierra Club 1-9 HSPM” pertains to the modeling assumptions that were used for the 2024 ELL CCCT RFP. The workpapers from Sierra Club 1-1 “Exhibit MJP 1-1 BP26 Final L&Cs w Chart HSPM” are based on ELL’s BP26 Final L&C, which is more current.
- b. The current deactivation assumption for Nelson 6 set forth in BP26 is 2028.
- c. See the Company’s response to Staff 1-90.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the Second Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 2-11

Part No.:

Addendum:

Question:

[REDACTED]

a.

[REDACTED]

b.

[REDACTED]

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. Subject to and without waiving the objections, the Company responds as follows.

- a. The Westlake proposal at the time of the RFP assumed the Nelson 6 unit would deactivate at the time of Westlake COD. The request made by Mr. Nguyen was to understand the potential cost impact from transmission should Nelson 6 continue to operate and the Westlake CCCT rely upon incremental NRIS.
- b. Mr. Nguyen’s updated analysis included in his Direct Testimony assumes Nelson 6 is operational at the same time Westlake comes online.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Louisiana Public Service
Commission Staff

Question No.: STAFF 1-90

Part No.:

Addendum:

Question

See the Direct Testimony of Nicholas D. Presser at 45. Regarding the continued operation of Nelson 6:

- a. Please describe in detail the Company's evaluation of continued operations at Nelson 6. In your response, please provide:
 - ii. The start date of the evaluation;
 - ii. The internal or external entities performing the evaluation;
 - iii. The decision criteria being applied; and,
 - iv. The current status and expected completion date.
- b. Please identify all operational scenarios being considered for Nelson 6 (e.g., full continued operation, seasonal operation, conversion, retirement, reserve status, etc.) and describe each scenario in detail.
- c. Please provide all analyses, studies, presentations, and/or internal memorandum evaluating continued operations for Nelson 6.
- d. Please provide all economic, reliability, environmental, and regulatory criteria used to determine whether Nelson 6 will continue operating. In your response, please provide for each criteria any quantitative thresholds or benchmarks used in the Company's evaluations.
- e. Please produce all models and assumptions used in evaluating the continued operation of Nelson 6.
- f. Please provide the amount of NRIS rights currently available at the Nelson site, and provide the amount currently assumed by the Nelson 6 generator.
- g. Please explain how the continued operation of Nelson 6 affects the need for, timing of, and siting of the proposed Westlake facility.
- h. Please explain whether the Company has evaluated siting alternatives for Westlake under scenarios where Nelson 6 continues operating, retires, and

operates in a limited or modified capacity. If so, please describe the results of each evaluation.

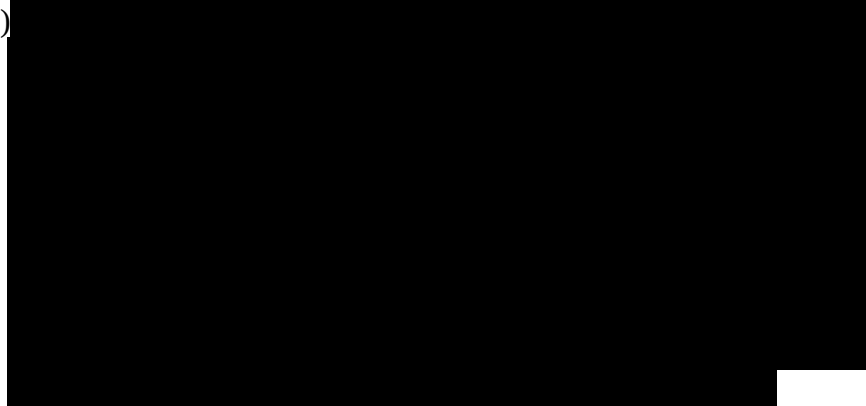
- i. Please produce any and all analyses comparing Westlake siting options under different Nelson 6 operational scenarios.
- j. Does the Nelson site remain the most reasonable option for siting Westlake under all operational scenarios considered for Nelson 6?
- k. Are there any scenarios under which the Nelson site is not the most reasonable option to site Westlake? If so, please explain those scenarios.
- l. Please produce any and all documentation supporting the contention that the Nelson site is the most reasonable siting option.
- m. Please describe all internal discussions, recommendations, or preliminary conclusions regarding continued operation of N6, including any preferred outcome.
- n. Please explain whether the Company has developed a preferred plan or recommendation regarding N6, even if not yet finalized, and describe that plan.
- o. Please produce all board materials, executive briefings, or management presentations discussing N6's future.
- p. Please state when the Company expects to make a definitive decision regarding N6 and identify all approvals required (internal and regulatory).
- q. Please explain why the Company proceeded with testimony asserting the Nelson site as the most reasonable option before making a definitive decision regarding N6.

Response:

The Company objects to the "Instructions" included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the statement that the requests are "continuing in nature" such that the Company should supplement under certain circumstances set forth in the "Instructions", as such statement and instruction seek to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. The Company further objects to this request as vague, ambiguous, and that it is overly broad and not reasonably calculated to lead to the discovery of relevant, admissible evidence. The Company interprets this request as seeking information pertaining to [REDACTED] being performed with respect to the Nelson 6 site. Subject to and without waiving the objections, the Company responds as follows.

a.

(i.) (ii.) (iv.)



(iii).



- b. See the response to subpart (a.) above.
- c. The Company objects to the request as overbroad. Subject to and without waiving the foregoing objections, please see the response to subpart (a.) above.
- d. The Company objects to this request as overbroad and premature. Subject to and without waiving the foregoing, please see the response to subpart (a.) above.
- e. The Company objects to the request that as premature. Subject to and without waiving the foregoing, please see the response to subpart (a.) above.
- f. There are 774 MW total at the Nelson site, of which 550 MW are attributable to Nelson 6.
- g. See the responses to Q63 and Q64 in the Direct Testimony of Nicholas D. Pressler.
- h. See the response to Q64 in the Direct Testimony of Nicholas D. Pressler.
- i. See the response to Q64 in the Direct Testimony of Nicholas D. Pressler.
- j. See the response to Q64 in the Direct Testimony of Nicholas D. Pressler.
- k. The Company objects to this request as overbroad. Subject to and without waiving the foregoing, ELL does not have any analysis indicating that the

Nelson site would not be the most reasonable location for siting the proposed Westlake project.

- l. The Company objects to this request as overbroad. Subject to and without waiving the foregoing, please see the response to Q64 in the Direct Testimony of Nicholas D. Pressler and the HSPM attachment included in response to Staff 1-70.
- m. The Company objects to this request as overbroad, unduly burdensome, and as seeking information that is irrelevant and/or not reasonably calculated to lead to the discovery of admissible evidence. The Company further objects to the request to the extent it seeks information protected by the attorney-client privilege and/or work-product doctrine. The Company further objects to this request as premature. Subject to and without waiving the foregoing, please see the response to subpart (a.).
- n. Please see the response to subpart (a.).
- o. The Company objects to this request as overbroad, unduly burdensome, and as seeking information that is irrelevant and/or not reasonably calculated to lead to the discovery of admissible evidence. The Company further objects to the request to the extent it seeks information protected by the attorney-client privilege and/or work-product doctrine. The Company further objects to this request as premature.
- p. 
- q. As referenced in response to Q63 and Q64 in the Direct Testimony of Nick Pressler, and as discussed in Q21-Q23 in the Direct Testimony of Michael J. Plaisance, the Company has identified a need for incremental generation at the Nelson site due to, among other factors, significant load growth in the near term, and the Nelson site is considered to be the most reasonable site for the new generator to serve the WOTAB planning area.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 1-11

Part No.:

Addendum:

Question:

Please provide all RFPs issued for new supply-side resources in the past two years, including the bids received and any analyses of the bids done by or for the Company.

- a. Refer to page 29 of the Direct Testimony of Patrick A. Sullivan, which states “the Company issued a number of RFPs contemporaneously with the 2024 CCCT RFP” that “cast a wide net for available generation options to serve its customers” and “performed a diligent search for available options to add generating capacity.”
 - i. In the Company’s response, please specify all resource options that bid into the RFPs that were issued contemporaneously with the 2024 CCCT RFP and which were considered as potential resource alternatives to the proposed Westlake and WF6 power stations.

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the statement that the requests are “continuing in nature” such that the Company should supplement under certain circumstances set forth in the “Instructions”, as such statement and instruction seek to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. The Company further objects to this request as overbroad and as seeking information that is irrelevant and/or not reasonably calculated to lead to the discovery of admissible evidence, including in particular with respect to the request that the Company provide “the bids received and any analyses of the bids done by or for the Company.” The Company further objects to the request to the extent it characterizes the contemporaneous RFPs as seeking resources “which were considered as potential resource alternatives to the proposed Westlake and WF6 power stations.” Subject to and without waiving the objections, the Company responds as follows.

- a. Please refer to Q14 of the Direct Testimony of Company Witness Michael J. Plaisance. For information concerning the RFPs mentioned in the referenced response in Mr. Plaisance's Direct Testimony, please access the relevant information through the following links:

- <https://rfp.entergy.com/ENTRFP/SEND/2024ELLDemandResponsePrograms/Index.htm>
- <https://rfp.entergy.com/ENTRFP/SEND/ELL3GWSolarRFP/Index.htm>
- <https://rfp.entergy.com/ENTRFP/SEND/2024ELLExistingResourceRFP/Index.htm>

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Louisiana Public Service
Commission Staff

Question No.: STAFF 1-48

Part No.:

Addendum:

Question

How many spots in MPA's production queue were secured and on what terms?

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. Subject to and without waiving the objections, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material (“HSPM”) and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

As at the time of this filing, Entergy had [REDACTED] secured with MPA, covering various resource needs across Texas (ETI), Louisiana (ELL), Mississippi (EML) and Arkansas (EAL). The terms for these slots are contained in the Exclusivity Agreement executed by Entergy with MPA which is included in the HSPM attachment.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the Second Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 2-2

Part No.:

Addendum:

Question:

[REDACTED]

a.

[REDACTED]

b.

[REDACTED]

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. Subject to and without waiving the objections, the Company responds as follows.

- a. A new-build combustion turbine (CT) is the standard assumption for the lowest-cost known option for adding long-term generation capacity. The CTs are designed with capability to burn up to 30% hydrogen by volume by the manufacturer. The company does not actually assume hydrogen is burned within its economic analysis.
- b. Please see the response to subpart (a).

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the Fourth Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 4-2

Part No.:

Addendum:

Question:

Refer to the Company's response to Sierra Club 2-2.

- a. Please confirm that the Company has no supporting documentation to share that support its decision to utilize a "Levelized CT w/Hydrogen" for its assumed capacity values or documentation to support the capacity value itself.
-

Response:

ELL incorporates in full the General Objections served with these Requests. The Company further objects to this request as an improper request for admission that is prohibited by Rule 63 of the Commission's Rules of Practice and Procedure. The Company further objects to this request as it misstates, misconstrues, or mischaracterizes ELL's response to Sierra Club 2-2. Subject to and without waiving the foregoing, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material ("HSPM") and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

Sierra Club 2-2 did not ask for support for "the capacity value itself"; the Company does in fact have support for that capacity value. Further, this request does not ask for the production of any documents, but the Company is nevertheless providing the relevant support as HSPM attachments to this response.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the Second Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 2-1

Part No.:

Addendum:

Question:

[REDACTED]

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. Subject to and without waiving the objections, the Company responds as follows.

The High Gas, High CO₂ case was not run for this RFP, thus no net costs are missing on this tab. This was a placeholder in the model in the event a High Gas, High CO₂ case was needed. Further, even if the High Gas, High CO₂ case had been run, Westlake and Waterford 6 would have still been the most economic resources in this RFP.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the Third Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 3-7

Part No.:

Addendum:

Question:

Refer to the Company's response to Sierra Club 2-1. Please provide the basis for the Company's assertion that "even if the High Gas, High CO2 case had been run, Westlake and Waterford 6 would have still been the most economic resources in this RFP," including any analysis performed in machine-readable Excel format with all inputs and assumptions clearly identified.

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving the objections, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material ("HSPM") and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

The heat rates for the Waterford 6 and Westlake CCCT are similar to the heat rate provided by the other proposal in the RFP, and thus the relative dispatch of the units would not be expected to materially change. [REDACTED] had significantly higher fixed costs than Waterford 6 and Westlake, and thus ELL is able to conclude the Waterford 6 and Westlake resources would still remain the most economic proposals in the RFP even under a high gas, high CO2 scenario.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 1-24

Part No.:

Addendum:

Question:

Refer to page 13 of the Direct Testimony of Phong D. Nguyen. Please provide the Henry Hub gas price forecast that ELL used in the economic evaluation of the proposed CCCTs in machine-readable Excel format.

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the statement that the requests are “continuing in nature” such that the Company should supplement under certain circumstances set forth in the “Instructions”, as such statement and instruction seek to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. Subject to and without waiving the objections, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material (“HSPM”) and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

See the HSPM attachment.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Louisiana Public Service
Commission Staff

Question No.: STAFF 1-89

Part No.:

Addendum:

Question

For all of the following:

- Waterford 6
- Westlake
- ELL's IRP assumption for a 1x1 CCCT
- Laidley's Franklin Farms generators
- Laidley's Waterford generator
- Evest's proposed 4 Richland Parish generators
- Evest's proposed 3 Point Coupee generators

Please provide a detailed comparison of:

- a. Total EPC contractor cost (\$/kW)
- b. Turbine/PIE cost (\$/kW)
- c. Engineering cost
- d. Other Construction cost not included above
- e. Contingency assumptions
- f. LTSA costs
- g. Financing assumptions
- h. Schedule for completion
- i. Total levelized cost on /kw-yr and /kw month.

Response:

The Company objects to the "Instructions" included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the statement that the requests are "continuing in nature" such that the Company should supplement under certain circumstances set forth in the "Instructions", as such statement and instruction seek to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. The Company further objects to this request as vague and ambiguous, because it does not specify the particular comparison that is sought. The Company further objects to the request to the

extent it seeks discovery into the Company's recent IRP filings, including because the most recent IRP proceedings are in their early stages, the assumptions are subject to further updates, and such discovery would be in contravention of the procedure established for submitting an IRP. Subject to and without waiving the objections, the Company responds as follows.

As a preliminary matter, and as applicable to all of the below information, the requested information seeks estimates and/or assumptions and, thus, information that is uncertain and/or subject to further development. Further, the Company is providing certain information from its most recently submitted IRP assumptions, but the Company specifically objects to any request for discovery into those assumptions.

- a-e, g. See the table below. These details are not currently available for Richland Parish 3-4 and Point Coupee 1-3. \$/kw are based on output at ISO conditions.
- f. LTSA costs have not been established across the fleet. Please see the Company's response to STAFF 1-92 for Waterford 6 and Westlake.
- h. The Company objects to the request as vague and ambiguous. The Company interprets this request as seeking the relevant in-service dates, which are provided in the table below.

	Franklin Farms	Waterford 5	Waterford 6	Westlake	Richland Parish 1&2
a-b. Total EPC cost including PIE					
c. Engineering cost					
d. Other Construction cost not included above (excluding Transmission)					
e. Contingency assumptions					
g. Financing costs					
h. Schedule for completion	Dec-28	Dec-29	Jul-30	Oct-30	Mar -30

- i. For Waterford 6 and Westlake, see levelized real fixed cost on the net benefit tab of the updated model provided as an HSPM attachment in the Company's response to Sierra Club 1-1. For all other generators, the analyses have not been performed. See the Company's response to SIERRA 1-26 for the Data Assumptions for the 2023 IRP and 2027 IRP data assumptions.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Environmental Defense
Fund

Question No.: EDF 1-14

Part No.:

Addendum:

Question:

In Paragraph XXXIX of its Application, ELL states that “a delay in the project schedule could lead to additional costs for constructing the Proposed Generators, including additional EPC costs, and could also delay the additional capacity and energy from the Proposed Generators, which could potentially lead to additional costs in the MISO marketplace.” Please explain what ratepayer protections are in place if the self-build options are not built in accordance with the identified timeline and ratepayers are exposed to additional costs in the MISO marketplace.

Response:

ELL incorporates in full the General Objections served with these Requests. The Company further objects to this Request as vague, ambiguous, overly broad, and as seeking information that is irrelevant and/or not reasonably calculated to lead to the discovery of admissible evidence. In particular, the phrase “ratepayer protections” is undefined, does not specify any category of costs (e.g., construction-related, market-related, financing-related, or otherwise), and lacks the clarity required for ELL to provide a complete and precise response. Subject to and without waiving the foregoing, the Company responds as follows:

As a preliminary matter, the referenced paragraph is in the section of the Application titled “Request for Timely Treatment” and is the paragraph of the Application in which the Company specifies the drivers supporting its need for certification by December 2026. The Company is seeking to protect ratepayers’ interests by alerting the Commission to the timing issues identified in the Application and by asking for Commission consideration at or before the specified December 2026 date.

Further responding, Company witness Michael J. Plaisance’s testimony describes the Company’s careful consideration of MISO’s resource adequacy framework and the financial exposure customers face in the MISO capacity and energy markets if sufficient in-zone resources are not available. Ensuring that the Proposed Generators move forward on schedule therefore mitigates customers’ exposure to potentially higher -priced capacity purchases and higher market energy costs.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the Third Set of Data Requests
of Requesting Party: Louisiana Public
Service Commission Staff

Question No.: STAFF 3-21

Part No.:

Addendum:

Question

[REDACTED]

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving the objections, the Company responds as follows.\

Information responsive to this request has been designated as Highly Sensitive Protected Material ("HSPM") and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

IM and Worley conducted an initial introductory meeting with the Self Build team on April 9. Follow-up meetings commencing on May 27 were conducted solely for the purpose of responding to IE questions and concerns. No new Self Build information was presented; all materials discussed were limited to information previously submitted in proposal responses. See the HSPM attachment, which consists of clarifying questions developed after the April 9th meeting and submitted to the Self Build team.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Louisiana Public Service
Commission Staff

Question No.: STAFF 1-30

Part No.:

Addendum:

Question

Please provide a detailed reconciliation of the project cost categories for WF6 and Westlake from:

- a. The initial self-build proposals submitted into the 2024 CCCT RFP.
 - b. The current cost estimates presented in this proceeding.
-
-

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. Subject to and without waiving the objections, the Company responds as follows.

- a. The WF6 self-build proposal was submitted as [REDACTED] for a July 2030 COD and the Westlake self-build proposal was submitted as [REDACTED]
- b. The WF6 cost estimate presented in this proceeding is \$2,027.2 million and the Westlake cost estimate presented in this proceeding is \$2,091 million. Please see the Company’s response to Staff 1-31 for detailed reconciliation.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Louisiana Public Service
Commission Staff

Question No.: STAFF 1-31

Part No.:

Addendum:

Question

For each cost increase identified in response to Staff 1-30, please provide:

- a. The amount of the increase
- b. The cause of the increase
- c. Whether the increase was foreseeable at the time of the RFP.

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. Subject to and without waiving the objections, the Company responds as follows.

WF6

	July 2030 ISD	July 2030 ISD	Difference	
	WF6 Capital Cost Estimate (Reg Filing in January 2026)	WF6 Capital Cost Estimate (Self-Build Proposal in March 2025)		
EPC Contract				As noted in Q54 in Direct Testimony of Nicholas D. Pressler, EPC completed its open book estimate development based on site specific conditions and updated subcontractor pricing. Contractor Fees also saw an increase.
Other Vendors				
Entergy Labor				
Other Expenses				
Total Direct Cost				
AFUDC/Financing Costs				AFUDC/Financing costs increased commensurate to overall project direct costs estimate.
Other Indirect Costs				
Total Indirect Cost				
Contingency				Advanced certainty of estimates resulted in refinement of risks, lowering of contingency.
Generation Project Cost				
Transmission Interconnection Cost				Self-Build Proposal submission to RFP clarified that scope and pricing for transmission interconnection were under development and ROM estimate ranged [REDACTED] [REDACTED]. The lower-end of this range was used for the Self-Build Proposal submission.
Transmission Upgrades Cost				
Total Project Cost	2,027.2			

Westlake

	Oct 2030 ISD	Dec 2030 ISD	Difference	
	Westlake Capital Cost Estimate (Reg Filing in January 2026)	Westlake Capital Cost Estimate (Self- Build Proposal in March 2025)		
EPC Contract				As noted in Q63 in Direct Testimony of Nicholas D. Pressler, EPC completed its open book estimate development based on site specific conditions and updated subcontractor pricing.
Other Vendors				
Entergy Labor				
Other Expenses				
Total Direct Cost				
AFUDC/Financing Costs				AFUDC/Financing costs increased commensurate to overall project direct costs estimate and different project and milestone- payment schedules.
Other Indirect Costs				
Total Indirect Cost				
Contingency				
Generation Project Cost				
Transmission Interconnection Cost				
Transmission Upgrades Cost				
Total Project Cost	2091.0			

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the Second Set of Data Requests
of Requesting Party: Louisiana Public Service
Commission Staff

Question No.: STAFF 2-1

Part No.:

Addendum:

Question

On May 15, 2026, ELL filed in Docket No. U-37425 its *Laidley Generation and Transmission Project Confidential Quarterly Monitoring Report for 2026 Pursuant to Order No. U-37425*.

Section III.E.ii of the Public Redacted Version states (in part):

Material changes in cost to complete ELL Generation and Transmission Projects

For Waterford 5, the primary drivers for the increased costs when compared to the original estimate are: Cost increases for site preparation and civil construction due to the geotechnical conditions at the site. The Waterford 5 site must be built up several feet above grade, and the design basis for Waterford 5 includes 120-foot piles. Additionally, escalation and increased costs for labor and subcontracted engineered equipment (e.g., air cooled condensers, electrical equipment, other equipment) since the summer of 2024.

Related to the Waterford 6 unit, for which ELL is seeking Commission certification in this proceeding, please:

- a. Describe whether the site chosen for the Waterford 6 unit has comparable geotechnical conditions to the site chosen for the Waterford 5 unit;
- b. If the site chosen for Waterford 6 unit does not have comparable geotechnical conditions to the site chosen for the Waterford 5 unit, please explain any and all differentiating factors;
- c. Describe whether ELL anticipates increases to the cost estimates presented to date for the Waterford 6 unit related to site preparation and civil construction due to geotechnical conditions at the site;
- d. Describe whether ELL anticipates the Waterford 6 site needing to be built up several feet above grade in order to accommodate siting of the Waterford 6 unit;

- e. Describe whether ELL anticipates the design basis for the Waterford 6 site to require 120-foot piles;
- f. Describe whether ELL anticipates any additional site work not previously contemplated or disclosed in its Application in this proceeding in order to accommodate siting of the Waterford 6 unit;
- g. Describe any and all site preparation and civil construction work ELL current anticipates will be necessary to accommodate the siting of the Waterford 6 unit;
- h. Provide any and all geotechnical surveys or studies performed by the Company, its affiliates, or any outside contractor and/or consultant related to the Waterford 6 site;
- i. Provide ELL's currently estimated cost of any geotechnical and/or site preparation work it contends is currently needed to prepare the site to accommodate siting of the Waterford 6 unit;
 - iii. Please provide the current representative cost class of this estimate.
 - iv. Please explain whether these costs are currently included in the total cost estimates provided for the Waterford 6 unit as presented in this proceeding.
- j. Provide all analysis completed by ELL related to site selection for the unit proposed to be installed at the Waterford site both prior to the application and after any significant costs increases which may have occurred.

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. Subject to and without waiving the objection, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material (“HSPM”) and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

- a. Please refer to Q47 in Direct Testimony of Nicholas D. Pressler. Waterford 6 is planned to be co-located with the Waterford 5 Unit (similar 1x1 CCCT)

on ELL-owned property in Taft, St. Charles Parish, LA, and, yes, Waterford 6 has comparable geotechnical conditions as Waterford 5.

- b. Please see response to (a) above.
- c. No, ELL does not at this time anticipate increases to the cost estimates presented to date for the Waterford 6 unit related to site preparation and civil construction due to geotechnical conditions at the site. While the Company does not anticipate an overage, there are still unknowns and risks to the project that could present with impacts to costs; however, the Company's risk mitigation program sufficiently takes this into account.
- d. ELL anticipates the Waterford 5 and Waterford 6 site being built up with structural fill up to the same finished grade of elevation. The cost estimates for Waterford 6 presented in this filing take this basis into account.
- e. Waterford 6 is using the same design basis for deep foundations as Waterford 5. The cost estimates for Waterford 6 presented in this filing take this basis into account.
- f. ELL does not anticipate any additional site work that was not previously contemplated or disclosed in ELL's Application in this proceeding in order to accommodate siting of the Waterford 6 unit at ELL-owned Waterford property. While the Company does not anticipate an overage, there are still unknowns and risks to the project that could present with impacts to costs; however, the Company's risk mitigation program sufficiently takes this into account.
- g. As contracted, based on the geotechnical investigations ELL had performed on the site, the grading plan for Waterford 5 and Waterford 6 consists of raising its site with structural fill to reach the final design grade. Further, the cost estimates presented in the Application include surcharging the site above existing grade to alleviate long-term settlement as prepared by the Engineer-of-Record. In addition, civil construction will include installation of deep foundations, underground utilities, and storm drainage typical of a new power plant development.
- h. Provided are the Contract Exhibit A.16.4.04.1 – EPC Geotech Memo and Waterford 5&6 Geotechnical Report, both of which are HSPM.
- i. Please see below:
 - i. The current representative cost for site preparation (structural fill and surcharge program) for Waterford 6 is [REDACTED]. This is a Class 3 estimate.
 - ii. Yes, this cost is currently included in the total cost estimate for Waterford 6 presented in this Application.

- j. Please refer to Entergy response to Staff 1-70 and its HSPM attachment for analysis completed by ELL related to site selection for the Unit. No cost increases from the estimates in the Application have occurred or are anticipated related to site preparation and civil construction for Waterford 6 due to geotechnical conditions at the site.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Environmental Defense
Fund

Question No.: EDF 1-17

Part No.:

Addendum:

Question:

In his February 2026 Direct Testimony (see Answer to Q45), Michael J. Plaisance identifies four circumstances that might warrant cancellation of either Proposed Generator, including (1) a well-founded, systematic increase in the forecasted cost of natural gas making alternatives more cost-effective and (3) a change in completion or operating costs of the Proposed Generators rendering them no longer in the public interest.

- a) Please identify the specific gas price level or trajectory that ELL would consider sufficient to trigger a cancellation analysis under factor (1).
 - b) Please identify the specific cost overrun amount or percentage above the current estimate that ELL would consider a “change in the cost to complete” sufficient to trigger a cancellation analysis under factor (3).
 - c) Please provide any break-even analysis ELL has performed showing at what gas price or capital cost overrun level the Proposed Generators would no longer produce net economic benefits to ratepayers.
-

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving these objections, the Company responds as follows:

- a. The Company objects to this request in that it relates to a hypothetical scenario and is not reasonably calculated to lead to the discovery of relevant, admissible evidence. Subject to and without waiving this objection, the Company responds as follows: The requested analysis has not been performed. Further responding, any decision to cancel either of the Proposed Generators would require a full analysis of the circumstances at the time.
- b. See the response to subpart (a).
- c. See the response to subpart (a).

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Louisiana Public Service
Commission Staff

Question No.: STAFF 1-95

Part No.:

Addendum:

Question

Please provide a complete system-wide generation and capacity supply plan corresponding to inclusion of each of the different load projection scenarios provided in response to Staff 1-94, including all resources available to serve load for each year. With respect to each version of the Load and Capability Report and any updates provided:

- a. Identify all resources included in the supply stack, including:
 - j. Existing generation resources;
 - ii. Approved but not yet in-service generation resources;
 - iii. Proposed generation resources in any pending or recently filed proceedings, including but not limited to:
 - 1. Laidley (Meta) resources;
 - 2. Evest Resources
 - 3. Cottonwood;
 - 4. Waterford 6 and Westlake;
 - 5. Bayou Cove;
 - 6. Big Cajun;
 - 7. Oxy;
 - 8. Zydeco Solar
 - 9. Votaw and Segno Solar Resources
 - 10. Any Solar Resources identified from U-36669 3GW Order
 - iv. Any capacity purchases or assumed market purchases (including PRA or bilateral purchases);
 - v. Any battery storage resources;
 - vi. Any other source of capacity or energy relied upon.
- b. For each resource identified above, provide:
 - vii. Nameplate capacity (MW);
 - viii. Accredited capacity for PRM purposes (MW);
 - ix. Expected in-service date;

- x. Expected retirement date, if applicable, including all planned or assumed retirements reflected in the Load and Capability Report or any related planning analyses;
- xi. Projected Net Book Value at retirement
- xii. Identification of whether the resource is included in:
 - 4. Base Case;
 - 5. Change Case; or
 - 6. Both;
- c. Provide a complete annual capacity balance for each year, including:
 - v. Total system load (from Staff 1-94);
 - vi. Total capacity requirement (including PRM);
 - vii. Total available accredited capacity;
 - viii. Capacity surplus or deficit (MW);
- d. For any year in which a capacity deficit exists:
 - iv. Identify the source of capacity assumed to meet the deficit;
 - v. Quantify the amount of such capacity (MW);
 - vi. Identify whether such capacity is assumed to be purchased from the market;
- e. Provide all supporting workpapers and calculations in Excel format with formulas intact, including any planning models or inputs used to develop the supply plan
- f. To the extent the Company has performed any scenario analyses or sensitivity analyses related to the inclusion or exclusion of any of the resources or loads identified above, please provide all such analyses.

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the statement that the requests are “continuing in nature” such that the Company should supplement under certain circumstances set forth in the “Instructions”, as such statement and instruction seek to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. The Company further objects to this request as vague, ambiguous, and overly broad. Subject to and without waiving the objections, the Company responds as follows.

- a.
 - i-ii. Please refer to HSPM attachment Staff 1-94 BP26 and Evest L&Cs_HSPM.
 - iii. Please refer to HSPM attachment Staff 1-94 BP26 and Evest L&Cs_HSPM. Refer to specific filings below for planned resources by name:



- iv-vi. Please see the HSPM attachment Staff 1-94 BP26 and Evest L&Cs_HSPM produced with the Company's response to Staff 1-94.
 - b-d. Please see the HSPM attachment Staff 1-94 BP26 and Evest L&Cs_HSPM produced with the Company's response to Staff 1-94.
 - e. Please see the HSPM attachment Staff 1-94 BP26 and Evest L&Cs_HSPM produced with the Company's response to Staff 1-94.

- f. Please see the HSPM attachment Staff 1-94 BP26 and Evest L&Cs_HSPM produced with the Company's response to Staff 1-94.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the Second Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 2-9

Part No.:

Addendum:

Question:

Refer to Sierra Club 1-15. Please provide any materials the Company has developed as part of its evaluation of surplus interconnection capacity across its system and any preliminary findings.

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company objects to this request as premature, overbroad, unduly burdensome, and as seeking information that is irrelevant and/or not reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving the foregoing, the Company responds that, as previously stated, the Company is currently in the early stages of evaluating the feasibility of such resources across its system. No preliminary findings have been identified at this stage.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Environmental Defense
Fund

Question No.: EDF 1-19

Part No.:

Addendum:

Question:

In his February 2026 Direct Testimony (see Answer to Q22), Michael J. Plaisance identifies Little Gypsy Units 2 and 3 (Amite South) and Nelson Station Unit 6 (WOTAB) as the aging coal and gas units whose deactivation drives the need for replacement generation. For each of Little Gypsy Unit 2, Little Gypsy Unit 3, and Nelson Station Unit 6:

- a) The unit's nameplate capacity, NRIS MW, and SAC for each year from 2020 through 2025;
 - b) The annual capacity factor for each unit for each year from 2020 through 2025;
 - c) The annual forced outage rate for each unit for each year from 2020 through 2025;
 - d) The total annual operations and maintenance (O&M) cost for each unit for each year from 2020 through 2025, broken down between fixed O&M and variable O&M, as well as any incremental capital expenses, including environmental and other expenses;
 - e) Whether the units have been fully depreciated or not. Please provide the most recent depreciation study;
 - f) The current assumed deactivation date for each unit in BP26, and whether ELL has provided or intends to provide MISO with a deactivation notice for each unit; and
 - g) For Nelson Unit 6 specifically: please describe the full range of options ELL is currently evaluating for continued operations, including but not limited to fuel conversion from coal to gas, and provide all analyses, studies, or documents reflecting ELL's evaluation of those options.
-

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving the objections, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material (“HSPM”) and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

- a. Generator nameplate ratings do not change annually. Little Gypsy 2 nameplate rating is 412MW, Little Gypsy 3 rating is 582MW and Nelson 6 rating is 615MW. See the HSPM for NRIS and SAC values.
- b. See the HSPM attachment EDF 1-19(b) capacity factor_HSPM.
- c. See the HSPM attachment EDF 1-19(c) N6 LG2 LG3 FOR 2020-2025_HSPM.
- d. See the Company’s response to Sierra 1-8 subparts (i) and (j).
- e. None of these units are fully depreciated. Please see the depreciation study provided as an HSPM attachment.
- f. As to Little Gypsy 2 & 3, May 31, 2030 was the BP26 deactivation assumption for Little Gypsy 2 & 3, and yes, in the sense that ELL is using MISO’s replacement process in connection with Waterford 6 to re-use the interconnection service associated with Little Gypsy 2 & 3. As to Nelson 6, February 29, 2028 was the BP26 deactivation assumption for Nelson 6, and no, ELL has not provided MISO with deactivation notice for Nelson 6.
- g. The Company objects to this request as overbroad. Subject to and without waiving the foregoing, please see the Company’s response to Staff 1-90 for the option currently being evaluated by the Company for Nelson 6.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Environmental Defense
Fund

Question No.: EDF 1-8

Part No.:

Addendum:

Question:

For each industrial customer whose load is cited as a driver of the need for the Proposed Generators in this docket (including at minimum the Hyundai steel mill, the CF Industries ammonia facility, the Woodside LNG facility), please explain whether the Company has had any communications about:

- a) How the customer intends to take electric service, including:
 - i) whether the customer has requested, or ELL has proposed, service under an existing tariff, a new tariff, a special contract, or some other arrangement;
 - ii) whether the customer has been offered or has requested service under a large load tariff or dedicated service arrangement;
 - iii) whether any large load tariff proceeding has been initiated or is contemplated in connection with serving any of these customers, and if so, identify the relevant docket;
 - iv) whether the terms of service have been finalized or remain under negotiation;
 - v) whether the customer has proposed, or ELL has discussed, a behind-the-meter generation arrangement, or any other arrangement under which the customer would supply some portion of its own capacity needs;
- b) Whether the customer has expressed any preference, requirement, or commitment to be served with clean, renewable, or low-carbon energy, including:
 - i) whether the customer has publicly stated a corporate sustainability goal, net-zero commitment, or renewable energy procurement target that would affect how ELL proposes to serve that customer's load;
 - ii) whether ELL has discussed with the customer any clean energy supply options — including renewable energy tariffs, power purchase agreements for solar or wind resources, green tariffs, or other mechanisms — as an alternative to or supplement to service from the Proposed Generators;

- iii) whether any clean energy supply arrangement has been included in any executed or proposed ESA or service agreement with the customer;
 - c) Whether the customer has expressed any capability or willingness to curtail load, participate in demand response programs, or accept interruptible or curtailable service, including:
 - i) the MW of curtailable or interruptible load identified for each customer, the conditions under which curtailment would be available, and the time horizon over which curtailment could be sustained;
 - ii) whether any demand response, curtailment, or interruptible service provisions have been included in any executed or proposed ESA with the customer;
 - iii) whether ELL has evaluated whether demand response or curtailment agreements with these customers could reduce or defer the need for one or both of the Proposed Generators, and if so, provide that analysis; and
 - iv) whether any load flexibility or curtailment capability associated with these customers is reflected in ELL's load forecast, capacity planning, or economic evaluation for this docket, and if so, describe how it was incorporated.
-

Response:

ELL incorporates in full the General Objections served with these Requests. The Company further objects to this request as it misstates, misconstrues, or mischaracterizes the testimony in this docket; as shown from the evidence presented in support of the Company's application, the referenced customer projects are only further support for a previously established need, as identified in the Company's 2023 IRP. The Company further objects to this request as seeking identifiable customer-specific information that, if released, would carry an unreasonable risk of undue harm to both the Company and each customer's competitive positions. The Company also objects to the request as overly broad and unduly burdensome and on the grounds that it seeks information that is irrelevant and not calculated to lead to the discovery of admissible evidence. Subject to and without waiving the foregoing objections, the Company responds as follows:

Each of the customers with projects identified in the HSPM attachment to Sierra 2-8 is on a standard rate approved by the Commission. Further, certain responsive information can be found in the attachments produced in response to Sierra 2-8 (including the Addendum thereto) and Sierra 3-11 (including the Addendum thereto).

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 1-12

Part No.:

Addendum:

Question:

Has the Company developed cost estimates for carbon capture and sequestration (“CCS”) at any of its existing coal or gas units, or for new/proposed gas units? If so, please provide the following in machine-readable Excel format with formulas intact:

- a. Capital and operating cost estimates for CCS at each unit
 - b. Assumed operating characteristics, such as carbon removal rate and whether carbon was assumed to be stored or transported elsewhere
 - c. Capacity and heat rate penalties for the unit associated with CCS
 - d. Assumed tax credits available to each CCS unit
 - e. In what futures or scenarios CCS will be included.
-

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the statement that the requests are “continuing in nature” such that the Company should supplement under certain circumstances set forth in the “Instructions”, as such statement and instruction seek to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. The Company further objects to this request on the grounds that it seeks information that is irrelevant and not reasonably calculated to lead to the discovery of relevant, admissible evidence. The Company further objects to the request for “any of its existing coal or gas units” as outside the scope of the docket. Subject to and without waiving the objections, the Company responds as follows.

ELL has not developed cost estimates or other analysis for carbon capture and sequestration (CCS) for the new/proposed gas units in this docket. As noted in the direct testimony of Nicholas Pressler at 5, lines 9 through 13, “the layouts of the sites

Question No.: SIERRA 1-12

for the Proposed Generators can accommodate carbon capture and storage (“CCS”) infrastructure and operations in proximity to the site.”

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37853

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 1-13

Part No.:

Addendum:

Question:

Has the Company developed cost estimates for burning hydrogen at any of its existing or new/proposed gas units? If so, please provide the following in machine-readable Excel format with formulas intact:

- a. Capital and operating cost estimates for burning hydrogen at each unit
- b. Assumed operating characteristics when burning hydrogen
- c. Percentage mix of natural gas versus hydrogen by year
- d. Costs of acquiring hydrogen, including production and distribution
- e. Assumed tax credits available
- f. In what futures or scenarios hydrogen will be included.

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the statement that the requests are “continuing in nature” such that the Company should supplement under certain circumstances set forth in the “Instructions”, as such statement and instruction seek to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. The Company further objects to the request for “any of its existing . . . gas units” as outside the scope of this docket and as seeking information that is irrelevant and/or not reasonably calculated to lead to the discovery of relevant, admissible evidence.” Subject to and without waiving the objections, the Company responds as follows.

ELL has not developed cost estimates or other analysis for burning hydrogen for the new/proposed gas units in this docket. As noted in the direct testimony of Nicholas Pressler at 5, lines 7 through 9, “By design, the MPA 501 JAC CT is capable of approximately 30% hydrogen co-firing, with the capability of supporting 100% hydrogen firing in the future with upgrades.”

CERTIFICATE OF SERVICE

I hereby certify that I have this 31st day of July, 2026, served copies of the Environmental Defense Fund's Direct Testimony upon all other known parties of this proceeding by e-mail.

Megan K. Terrell

Megan K. Terrell